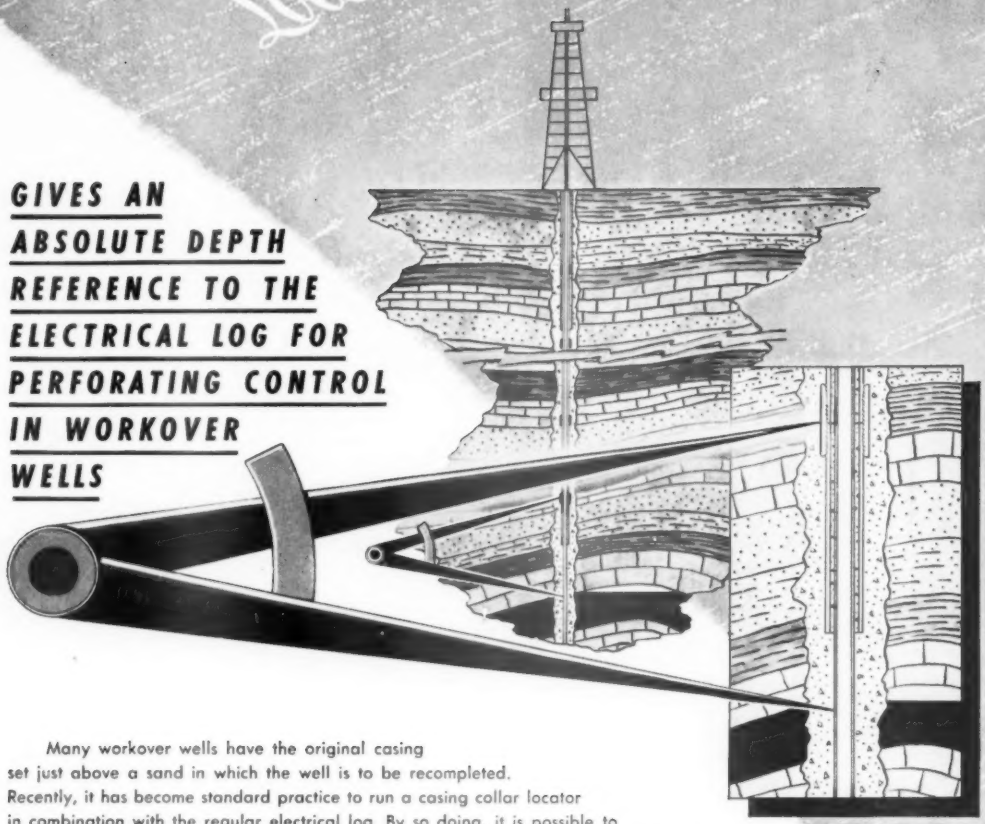
JOURNAL OF

Petroleum Technology

MARCH, 1951

The SCHLUMBERGER Casing Collar Locator

GIVES AN ABSOLUTE DEPTH REFERENCE TO THE ELECTRICAL LOG FOR PERFORATING CONTROL IN WORKOVER WELLS



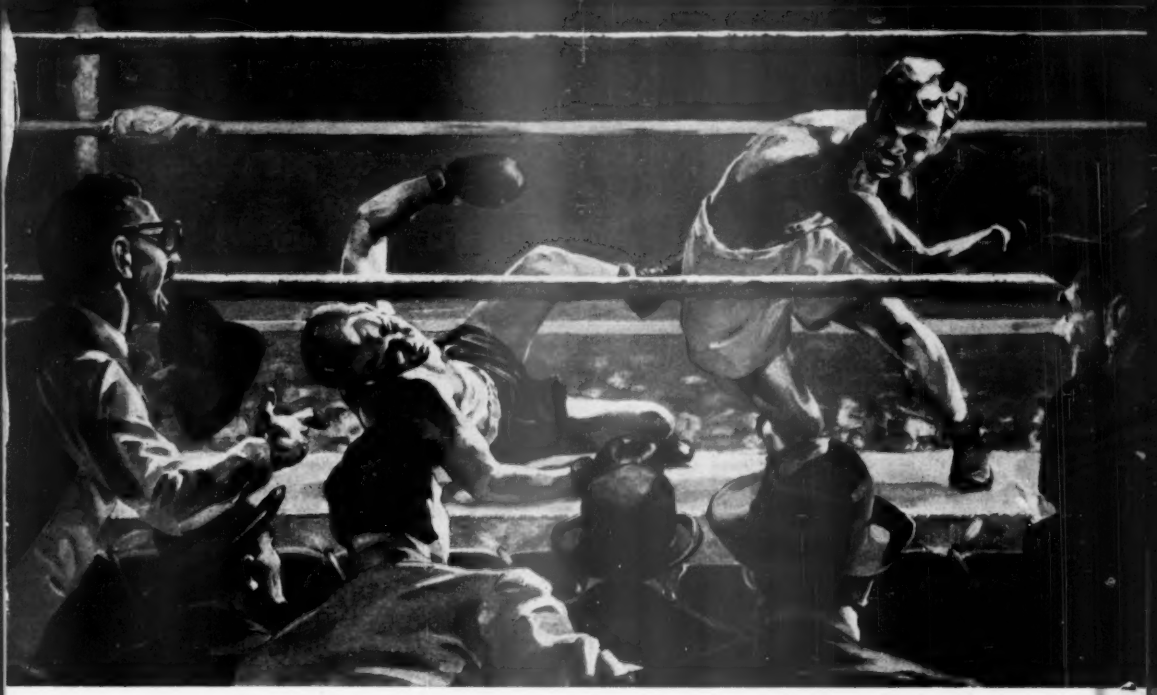
Many workover wells have the original casing set just above a sand in which the well is to be recompleted. Recently, it has become standard practice to run a casing collar locator in combination with the regular electrical log. By so doing, it is possible to establish definite distances between the casing collars and the projective formation. When the well is perforated, the same collars can be relocated and the shots placed with absolute control.

You should consider running a Casing Collar-Electrical Log combination on your next workover well.

SCHLUMBERGER

The Schlumberger Casing Collar Locator is another important development of Schlumberger's progressive program of research and engineering to provide advanced services to the oil industry.

SCHLUMBERGER WELL SURVEYING CORPORATION • HOUSTON



CHAMPIONS DON'T WIN BY PULLING PUNCHES

To win consistently in the ring a man has to punch as hard and straight as he knows how. And to win consistently in the sometimes uncertain business of producing oil, you have to use casing perforating that punches straight through all casing, cement and far back into the formation. The record of results in thousands of wells perforated with the modern Welex Jet Process *proves* that JETS give 300% deeper penetration than any other practical method. On job after job results have proven that JET perforating can make a profitable oil well where other methods failed. Men who know will tell you that results cost less with Welex JETS. Call your nearest Welex Station for prompt service day or night.

ORIGINATORS OF Welex JET PERFORATING

Welex

JET SERVICES INC.

GENERAL OFFICE: 3909 Hemphill Street • Fort Worth 9, Texas
FIELD STATIONS: Shreveport • Ardmore • Lindsay • Shawnee • Corpus Christi
Falfurrias • Houston • Kilgore • Odessa • Snyder • Wichita Falls

Professional Services

This space available only to AIME members. Rates upon request.

AMSTUTZ AND YATES, INC.
Petroleum Engineers and Geologists
Estimates of Oil & Gas Reserves
Property Valuations, Reservoir Analyses
Geologic Investigations
406 KFH BLDG., WICHITA 2, KANS.

BERGER AND PISHNY
Consulting Geologists and Engineers
901 Commercial Standard Bldg.
Fort Worth 2, Texas
Walter R. Berger — Chas. H. Pishny

JOHN G. CAMPBELL, CHEMIST
Licensed for
Fluorometric Analysis of Well Cuttings
Podbielniak & Charcoal Analyses
Waters - Oil Field Brines - Cores
CORPUS CHRISTI, TEXAS — PHONE 4-5612

CHEMICAL & GEOLOGICAL LABORATORIES
Consultants - Investigations - Evaluations
James G. Crawford.....Chemical Engineer
H. E. Summerford.....Petroleum Geologist
F. Raymond Wheeler...Petroleum Engineer
P. O. BOX 279 — CASPER, WYOMING

CRUTCHFIELD AND PRUETT
CONSULTING PETROLEUM ENGINEERS
224 Wilson Building
CORPUS CHRISTI, TEXAS
John W. Crutchfield — *Horton T. Pruett*

DENTON-SPENCER COMPANY, LTD.
CONSULTING PETROLEUM ENGINEERS
Lancaster Bldg. — Calgary, Alberta

EARLOUGHER ENGINEERING
Petroleum Consultants - Core Analyses
Specializing in Secondary Recovery
Investigations - Appraisals - Operations
311-319 East Fourth Street
TULSA 3, OKLAHOMA
Office 2-5129 — Laboratory 2-6139

HERSHAL C. FERGUSON
Consulting Geologist and Paleontologist
Esperson Building
HOUSTON, TEXAS
825½ Gravier Street — New Orleans, La.

FITTING, FITTING & JONES
Engineering & Geological Consultants
Petroleum — Natural Gas
Box 1637
223 S. Big Spring St. — Midland, Texas

MICHEL T. HALBOUTY
CONSULTING GEOLOGIST
AND PETROLEUM ENGINEER
Shell Building
Houston 2, Texas — Phone PR-6376

HAMILTON AND CHOMBART
Well Log Consultants
Wright Building
Tulsa, Oklahoma
Electric Log Analysis and Review Interpretation
Oklahoma-Kansas Log Analysis Service
Log Analysis Conferences
Phones 3-7055 — 7-1825
DR. R. G. HAMILTON — L. G. CHOMBART

WILLIAM HURST
Petroleum Consultant
Reservoir Engineering - Primary & Secondary Recovery, Gas Cycling, Evaluations
6445 BROMPTON ROAD
Madison 1181
HOUSTON, TEXAS

KELLER & PETERSON
Petroleum Consultants
Reserve Estimates — Property Appraisals
Petroleum and Geological Engineering
Reservoir Analysis
MIDLAND, TEXAS
P. O. Box 1787 — Phone 1471
W. O. Keller — L. F. Peterson

JAMES A. LEWIS ENGINEERING
Petroleum Reservoir Analysts
Core Analysis, Relative Permeability, Restored State, Resistivity, Flood Tests
Comprehensive Reservoir Studies
Pressure Maintenance, Secondary Recovery
6923 Snider Plaza — P. O. Box 237
Dallas 5, Texas — Evansville 8, Ind.
Ph: L6-3836 — Ph: 4-5318

W. T. MENDELL
Engineering & Geological Consultant
Second National Bank Building — Houston, Texas — CApital 7612

CLEVELAND O. MOSS
CONSULTING PETROLEUM ENGINEER
Estimates of Oil and Gas Reserves
Valuation—Production Problems—Proration
208 MIDCO BLDG. — TULSA 3, OKLA.

OILFIELD SERVICE COMPANY
Electric Logs — Gamma Ray — Caliper
Water Input Profiles
Specializing in Secondary Recovery
CHANUTE, KANSAS

ERNEST K. PARKS
CONSULTING PETROLEUM ENGINEER
Planning, Direction and Examination of Oilfield Operations, Estimates of Oil and Gas Reserves, Oil Property Valuation
614 S. HOPE STREET, LOS ANGELES 17, CALIF.
Telephone: VanDyke 4659

WALTER ROSE
Box 1581 — *University Station*
AUSTIN, TEXAS

SOL SMITH
CONSULTING ENGINEER
PETROLEUM AND NATURAL GAS
Reserves — Deliverability
Oil and Gas Proration
826 BROWN BUILDING
AUSTIN, TEXAS — PHONE: 89498

WM. H. SPICE, JR.
Consulting Geologist
2101-03 Alamo National Building
SAN ANTONIO 5, TEXAS

R. W. TESCH
PETROLEUM CONSULTANT
Valuation — Development — Management
Electric Bldg. — Fort Worth, Tex.

JOSEPH B. UMPLEBY
6214 PARK LANE
DALLAS 5, TEXAS

HAROLD VANCE
CONSULTING PETROLEUM ENGINEER
Pet. Engr. Dept. — A & M College
College Station, Texas

Journal of Petroleum Technology

Editorial Board

RICHARD W. FRENCH

JOHN E. SHERBORNE

THOMAS C. FRICK

★

Editorial and Business Staff

EDITORIAL DIRECTOR

JOE B. ALFORD

EDITOR

JESS E. ADKINS

ASSOCIATE EDITOR

VIRGINIA BEILHARZ

EDITORIAL ASSISTANTS

MARJORIE ANN WHITE

KAY HIBBARD

MARJORIE PARKS

Journal of Petroleum Technology is published monthly. Domestic Subscription: North, South and Central America, $8; foreign, $9; to AIME members, $6, or $4 if in combination with subscription to either Journal of Metals or Mining Engineering. Single copies 75 cents; special issues, $1.50. Registered cable address AIME. Printed in USA. Copyright 1951 by American Institute of Mining & Metallurgical Engineers.

Official Publication

Petroleum Branch

American Institute of Mining & Metallurgical Engineers

Statements and opinions contained in the JOURNAL are, unless otherwise indicated, attributable only to the author, and do not necessarily reflect the views of the AIME, its officers, committees, or other agencies.

Executive Secretary

JOE B. ALFORD

Editorial and Business Office

601 Continental Building
Dallas, Tex.
Phone:
STerling 4213 RIverside 9437

Officers of the Petroleum Branch

CHAIRMAN

Richard W. French
Sohio Petroleum Co.
Cleveland, Ohio

VICE-CHAIRMEN

Lincoln Elkins
Sohio Petroleum Co.
Oklahoma City, Okla.

Paul R. Turnbull
La Gloria Corp.
Corpus Christi, Tex.

EXECUTIVE COMMITTEE

John S. Bell
Humble Oil and Refining Co.
Tyler, Tex.

Harold Decker
Houston Oil Co. of Texas
Houston, Tex.

R. C. Earlougher
Earlougher Engineering
Tulsa, Okla.

Thomas C. Frick
Atlantic Refining Co.
Midland, Tex.

John R. McMillan
Fullerton Oil Co.
Pasadena, Calif.

Harry H. Power
University of Texas
Austin, Tex.

Dean H. Sheldon
Consulting Engineer
South Pasadena, Calif.

John E. Sherborne
Union Oil Co. of Calif.
Whittier, Calif.

H. J. Struth
Petroleum Consultant
Dallas, Texas

TREASURER

R. E. Heithecker
Seaboard Oil Co.
Dallas, Tex.

Branch Committee Chairmen and Vice-Chairmen

MEMBERSHIP

Jack H. Beesley
Baroid Sales Division
Tulsa, Okla.

PUBLICATIONS COMMITTEE

J. M. Bugbee, Chairman
Shell Oil Co.
Houston, Tex.

John P. Hammond, Vice-Chairman
Amerada Petroleum Corp.
Tulsa, Okla.

PRODUCTION REVIEW COMMITTEE

E. W. Berlin, Chairman
Socony-Vacuum Co.
New York, N. Y.

R. B. Gilmore, Domestic
DeGolyer and MacNaughton
Dallas, Tex.

A. H. Chapman, Foreign
Arabian American Oil Co.
New York, N. Y.

Officers of the AIME

President, W. M. Peirce; Vice-Presidents, Joseph L. Gilson, Michael L. Haider; Directors, Thomas G. Moore, Charles E. Lawall, John F. Myers, Fay W. Libbey, Albert C. Rubel; Vice-President and Treasurer, Andrew Fletcher; Secretary, E. H. Robie.

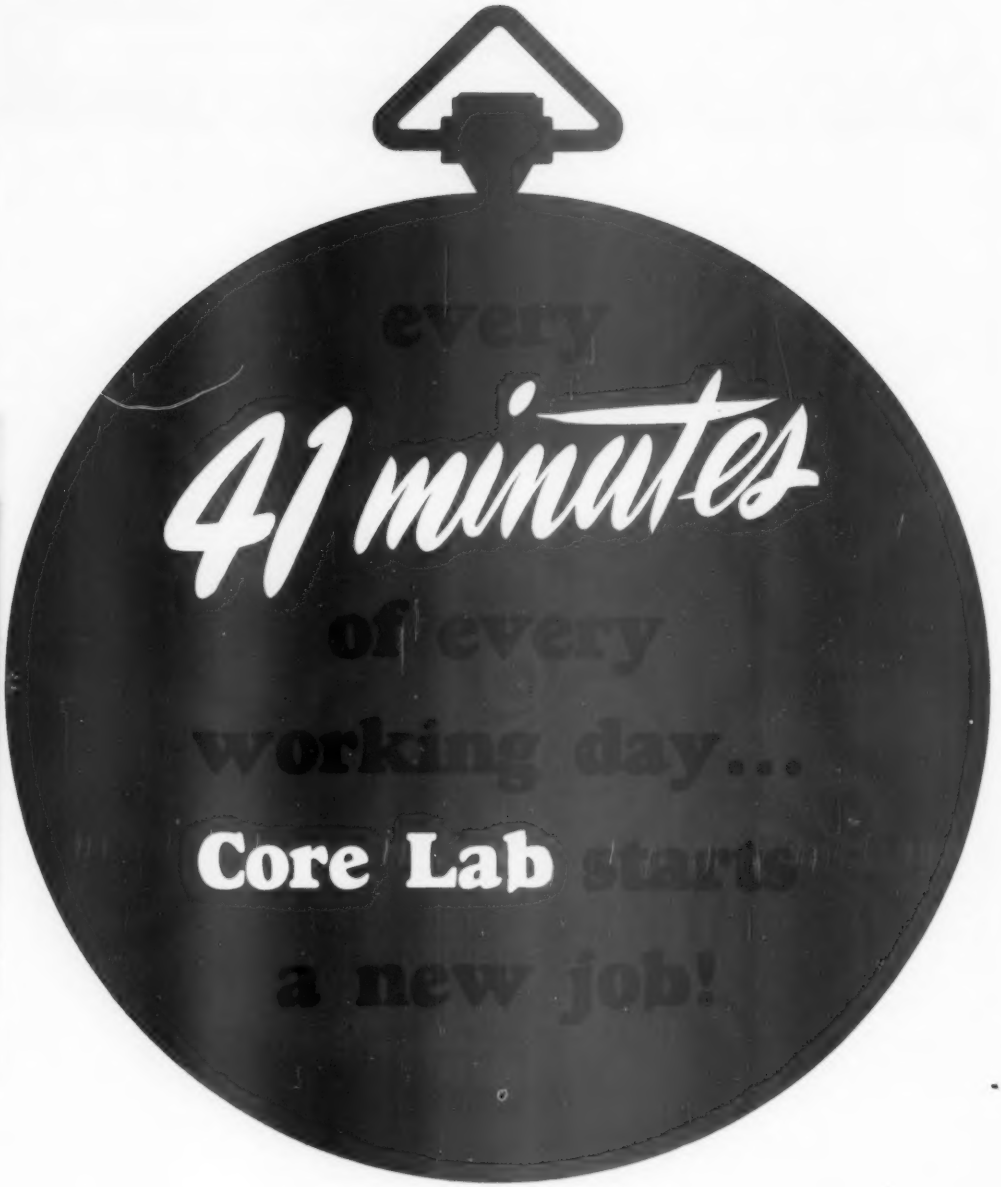
Journal of Petroleum Technology is published monthly by the American Institute of Mining and Metallurgical Engineers at 29 West 39th Street, New York 18, N. Y. Entered as second class matter January 31, 1949, at the post office at New York, N. Y., under the Act of March 3, 1879. Additional entry at Dallas, Texas.

Publisher's Representatives

McDonald-Thompson
3727 West 6th St.
Los Angeles 5, Calif.

1118 Odeans Drive
Dallas, Texas

Allen Associates
324 Madison Avenue
New York, N. Y.



"Providing more reservoir revenue . . . through the production of more recoverable oil."

THE PROFESSIONAL MAGAZINE FOR PETROLEUM ENGINEERS

Journal of Petroleum Technology

Vol. III | MARCH, 1951 | No. 3

TABLE OF CONTENTS

Editorial Features — Section 1

Editorial: On Stockpiling Oil, by R. W. French . . . 9
The Development and Operation of LPG Storage Cavities in Salt Strata, by K. C. Howard 10
1950 Domestic Production Review 12
Technical Note: The Calculation of Water Resistivities from Chemical Analyses, by H. F. Dunlap and R. R. Hawthorne 17
Engineering Developments in Local Sections 18

Petroleum Transactions

Capillary Pressure Investigations, by Harry W. Brown . 67
Variable Characteristics of the Oil in the Tensleep Sandstone Reservoir, Elk Basin Field, Wyoming and Montana, by Ralph H. Espach and Joseph Fry . 75
Relative Permeability to Liquid in Liquid-Gas Systems, by L. A. Rapoport and W. J. Leas 83

Institute Affairs — Section 2

Drift of Things, by Edward H. Robie 1
Personals 4
Petroleum Branch, AIME, Membership 5
Employment Notices 5
Letters to the Editor 6
Local Section Meeting Calendar 8
Advertisers' Index 8

On the Cover — Symbolic of production everywhere is the railroad tank car, one of the links in the marketing process of the petroleum industry. This month's cover depicts long lines of such cars nearing the loading racks at the Beaumont, Tex., refinery of the Magnolia Petroleum Co. For a review of 1950 domestic production, turn to Page 12, Section 1.

FOR

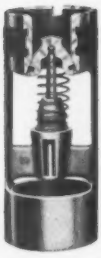
- successful "first-time cementing"
- remedial cementing
- many special drilling and production techniques...

For a "sure-fire" shut-off use this Baker Casing Bridge Plug (Product No. 400-D) which can be run and set either on tubing or a *wire line*. ★ For squeeze cementing, acidizing or testing, use the old reliable Baker Cement Retainer, Product No. 400.

The Baker Retainer Production Packer (Product No. 415-D) meets most production requirements with unequalled flexibility, safety and economy. ★ Can be set on tubing or drill pipe—(or on a wire line by your choice of the leading electric wire line service organizations).

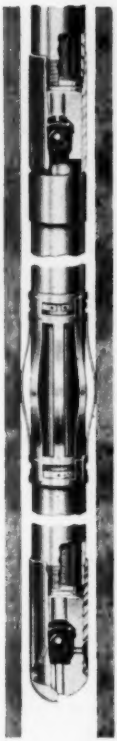
Save money, save time, get the

Don't waste time and money hauling kinked Kellys and bent drill pipe to the shop! ★ The Baker Portable Kelly and Pipe Straightener (Product No. 550) does a better job while the Kelly or pipe is suspended vertically through the table; and avoids possible damage in transporting and handling.



Use Baker BAKWIK Drill Pipe Floats (Product No. 480) to reduce wear and tear on wire lines and rig equipment. ★ Greatly reduces possibility of wet strings due to clogged bits and drill pipe.

.. You will have "BETTER RESULTS WITH BAKER"



For successful "first-time" cementing use a Baker Cement WASH-DOWN WHIRLER Float Shoe (Product No. 120) centered in the hole by a Baker Casing Centralizer. ★ If an additional "float" valve is desired, run a Baker Cement Float Collar (Product No. 101) up the string. ★ If one "floating unit" is sufficient for your casing string, use a Baker Float Collar a joint or two up the string and a Baker Cement WASH-DOWN WHIRLER *Guide* Shoe (Product No. 121) on bottom.

When your casing is equipped with Baker Model "G" Casing Centralizers (Product No. 910-G) you *know* that is REALLY CENTERED with better chances for a "first-time" water shut-off. ★ ★ In directional holes "sled-runner-action" of the springs helps to get pipe to bottom.

No more torn swab rubbers or packing elements. Slips on testers or packers can always contact casing. ★ A Baker ROTO-VERT Casing Scraper (Product No. 620-C) run on drill pipe, or a *wire line*, scrapes casing free from gun-shot burrs and hardened cement.

job done... Specify BAKER in '51

BAKER OIL TOOLS, INC.

HOUSTON • LOS ANGELES • NEW YORK

DOWELL STRATALIFT *using* JEL-ACID provides an improved method of increasing production by fracturing formations

Jel-Acid, a recent Dowell development, is thickened hydrochloric acid. Forced into sand, dolomite or limestone formations at high pressure, it provides a fracturing effect that forms permanent new drainage channels. This process, called STRATALIFT, has proved highly successful for increasing production in many wells where ordinary acidizing or shooting failed to produce results.

A well completed in the Arbuckle had an initial production of 11 BOPD. A conventional acid treatment, a 10-quart shot of nitroglycerin and a second acid treatment all failed to increase production. STRATALIFT with Jel-Acid was then employed and the well is now producing 91 BOPD, *a 727% increase!*

STRATALIFT has many advantages. Jel-Acid provides the viscous fluid needed for formation fracturing and, in addition, reacts with the soluble part of the formation. Jel-Acid has a wide range of viscosities, easily controlled, making it adaptable to formations of various permeabilities. Further, Jel-Acid will not burn. Finally, Dowell, the pioneer in acidizing, has the right equipment for the job and the long experience needed for the best possible treatment. For complete information on this new development, call your nearest Dowell station or write to Tulsa.

DOWELL INCORPORATED
TULSA 3, OKLAHOMA
Subsidiary of The Dow Chemical Company

DOWELL
ACIDIZING SERVICE

Ask your nearest Dowell station for complete information on these Dowell services and products: Acidizing Service, Electric Pilot Services, Plastic Service, Chemical Scale Removal Service for heat exchange equipment, Jetlake, Paraffin Solvents, Magnesium Anodes for Corrosion Control, Saran Rubber for corrosion resistant tank linings and Bulk Inhibited Hydrochloric Acid.

"First in Acidizing . . . since 1932"

Look to **DOWELL**

FOR OIL INDUSTRY CHEMICAL SERVICE

Editorial Comment—
On Stockpiling Oil

By R. W. French
Sohio Petroleum Co.

IF YOU review our past editorial pieces, you may be struck as I was by their variety — despite our stratified professional training and immediate interests. From problems-and-progress of our AIME organization itself, they touch on many phases of development and use of engineer-citizens, winding up in such topics as greater participation in politics and estimation of undiscovered reserves.

Still further reflection suggests a curious relationship to one vital common problem now facing us — subsurface stockpiling of oil! Why a problem? In what connection? Here is one view, in brief:

WHY A PROBLEM?

1. Although our domestic supply and reserves (reserves are significant only as tomorrow's supply) may continue to increase as they have historically, we still face increasing imports or substitutes to balance climbing demand, even in peacetime.
2. Despite curtailment of "civilian" demand, and uncertainty of actual oil requirements for fuel, lubrication, and chemical material, we have no proof that adequate domestic supply will be available in time of war.
3. Unless such unlikely proof is forthcoming, we face the choice of stockpiling oil or substituting other energy sources such as coal, shale, gas, alcohol or even hydro-electric, solar, or nuclear energy, etc., through displacement or conversion.

IN WHAT CONNECTION?

If we agree that there is some problem, how do we think it should be met (1) as engineers or business men, (2) as citizens? Immediately we can ask knotty questions, theoretical, technical, and "practical," such as:

(a) How much oil should be imported to defer current domestic production for stockpiling?

(b) Would it ever be feasible or necessary to actually inject oil into natural underground reservoirs for storage, with the obvious cost disadvantages and uncertainties of later recovery?

(c) Who would own stockpile oil and what compensation or arrangements would be made with owners, operators, and royalty holders?

(d) Who would determine when the oil should be produced? At what price? For whose refineries?

(e) What attitude and action would be taken by state and federal tax and regulatory authorities? And would this be impossible without federal control?

But how does this all relate to our past editorial topics? Take "registration of engineers" by Geis — this says engineers must have certain competence, certainly have responsibility to the public. "Engineering education" by Calhoun, and Gaylord's excellent statement on "specialization" covered the academic and training phases basic to successful discharge of engineering work today.

Then came views by Bullard and Rubel urging engineers to extend their efforts beyond engineering, to interpret and act in community and citizenship matters as aggressively and effectively as they do in their professional work. Returning to DeGolyer's provocative and timely contribution on estimation of undiscovered reserves, we see that it too bears directly on this topic as one important factor in "stockpiling" to assure future supply.

To me, these random topics bear on many aspects of today's problems but with particular force on our nation's future supply of crude oil. Those who heard Railroad Commissioner William Murray's timely and forthright address at the AIME Annual Meeting in St. Louis last month will not forget his plea for realistic engineering work as a requisite of national defense.

Whether your primary work is in exploration, drilling, production, research or management, this "stockpiling" problem and its solution affect you professionally. Regardless of occupation, it concerns every American ultimately. Individually we must give it our most objective and far-sighted attention. ★ ★ ★

THE DEVELOPMENT and OPERATION of LPG STORAGE CAVITIES IN SALT STRATA

By K. C. Howard

Richardson and Bass, Fort Worth

The process of storing liquefied petroleum gases in reservoir salt formations has proved successful in West Texas. Though untried, the process is believed to be applicable to formations other than salt.

ABSTRACT

Underground storage of liquefied petroleum gases in reservoirs dissolved by circulating fresh water in Upper Permian salt beds in West Texas has been very successful. One system of 55,000 bbl capacity is in operation in Upton County, Tex., while another system in Winkler County, Tex., is now at approximately 25,000 bbl capacity and is in the process of being enlarged.

Development of the Winkler County project was delayed at about 8,000 bbl capacity for the purpose of testing and to allow demonstrations of the system to the industry. In these tests, recovery of injected propane varied from 95.9 to 99.7 per cent of injected volumes. The recovered LPG in all tests had increased in vapor pressure and had picked up a slight trace of moisture.

The process, though untried, is believed to be applicable to formations other than salt such as shales using partially saturated salt water, and possibly to limestone formations using hydrochloric acid.

This paper was presented at the Petroleum Branch Fall Meeting in New Orleans, La., October 4-6, 1950.

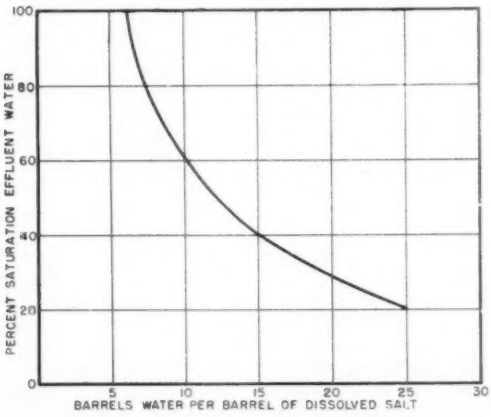


FIG. 1 — BARRELS OF CIRCULATING WATER PER BARREL OF DISSOLVED SALT.

DESCRIPTION OF PROCESS

It is believed that the practicality of artificially formed underground LPG storage space is established by the performance to date of two such systems in West Texas. In these systems, storage space was dissolved out of salt beds by circulating fresh water.

The Upper Permian salt section of West Texas is generally a little over 1,000 ft thick, and in the storage well in the Keystone Field, the top of the salt is at 1,170 ft. The salt is overlain with a stratum of good solid anhydrite 100 ft in thickness in which 9⅝-in. casing was set at 1,162 ft. The hole was bottomed at 1,770 ft in salt and 2.5 tubing was run to 1,748 ft.

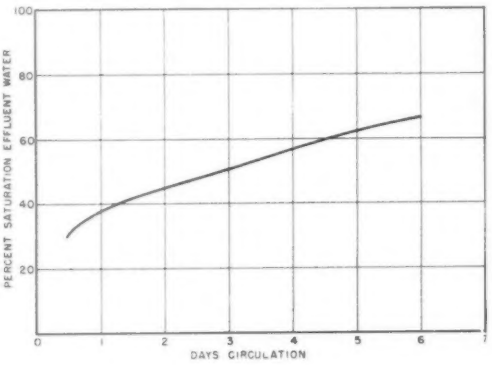


FIG. 2 — SALT SATURATION OF EFFLUENT WATER.

A conventional shallow well Christmas tree was used and hooked up with a positive displacement pump so that fresh water could be injected either into the tubing or into the annulus.

Fresh water was injected at 5.5 bbl per minute. The first returns were only 10 per cent saturated with salt, but as the hole was enlarged thereby increasing the area and time the salt was exposed to water, the salt saturation of the effluent water continuously increased and leveled off at approximately 97 per cent saturation after about 14 days circulation. The effluent water saturations for the first few days' circulation

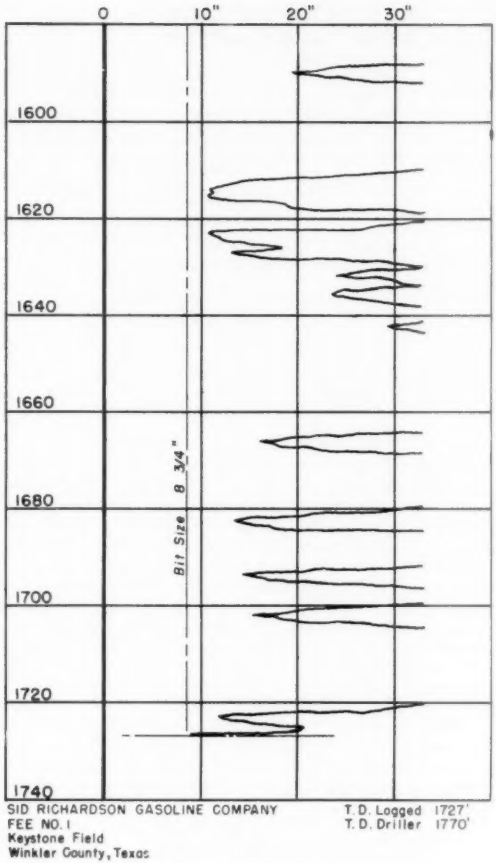


FIG. 3 — CALIPER LOG AFTER CIRCULATING 50 HOURS.

are shown in Fig. 2. At present the capacity of the Winkler County system is about 25,000 bbl and circulation will be continued until a capacity of 50,000 bbl is obtained.

The salt beds consist mostly of sodium chloride with some chlorides of potassium and magnesium interspersed with anhydrite stringers and other insoluble matter. It was estimated that at 100 per cent saturation, 6.1 bbl of water will dissolve one barrel of formation and the computed volumes of space formed using this estimate checked very closely with the dissolved volume indicated by a caliper survey. The solubility of salt in water varies only to a small degree with temperature, and the estimated solubility of the salt in the Winkler County project at an average circulating temperature of 80°F is shown in Fig. 1. It is believed that the volume of salt dissolved out of a formation may be determined with sufficient accuracy for all practical purposes from the quantity of fresh water injected and the salinity of the effluent water. The relative solubility of various strata in the salt formation is shown in Fig. 3, which is a representative portion of a caliper survey run after approximately 50 hours circulation. The dissolved volume at the time of this survey was 1,115 bbl.

No detectable loss of fluids was caused as surface pressures in excess of 500 psi were applied to the annulus on various occasions while circulating. This surface pressure plus the hydrostatic head of the circulating fluid caused a pressure against the salt formation equivalent to a gradient of 0.86 psi per foot. Consequently, as no such pressures are required in normal operation, the possibility of loss of stored products to the formation is considered to be remote.

As the Upper Permian salt section has shown no tendency to break down at excessive pressures, it has been found most convenient to store the LPG above water in the storage space by injecting LPG into the annular space displacing the water down and up through the tubing to the surface. LPG is recovered by injecting water into the tubing thereby displacing the LPG back through the annulus.

The surface pressure of the LPG if stored over water is proportional to the depth of the LPG-water contact as the system is merely a "U" tube with salt water inside the tubing and LPG in the annular space. The surface pressure of the LPG is equal to the difference in the columnar heads of the two fluids. The difference in columnar heads of saturated salt water and propane is about 300 psi per 1,000 ft. Storage of LPG obviously necessitates sufficient pressure to prevent vaporization of the product plus sufficient pressure to conveniently transfer the product, or at least furnish adequate pressure to the suction end of a transfer pump. A formation that will support a column of saturated salt water and as much as 700 ft deep, may be used satisfactorily for the storage of 200 psi vapor pressure propane, and of course, more shallow formations may be used for the storage of products with less vapor pressure.

The process is deemed to be practical in formations that will not support a column of water, provided the formation is at sufficient depth. Several schemes may be employed. For

Continued on Page 3, Section 2

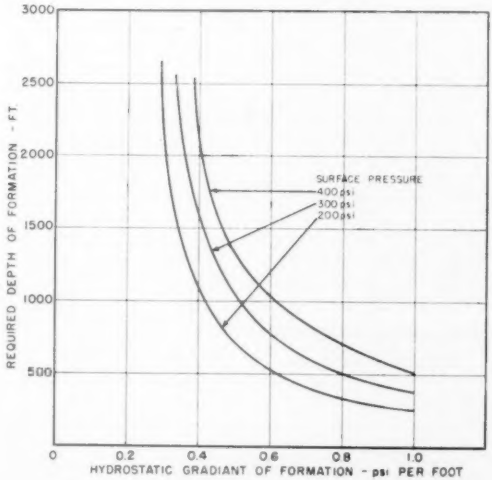
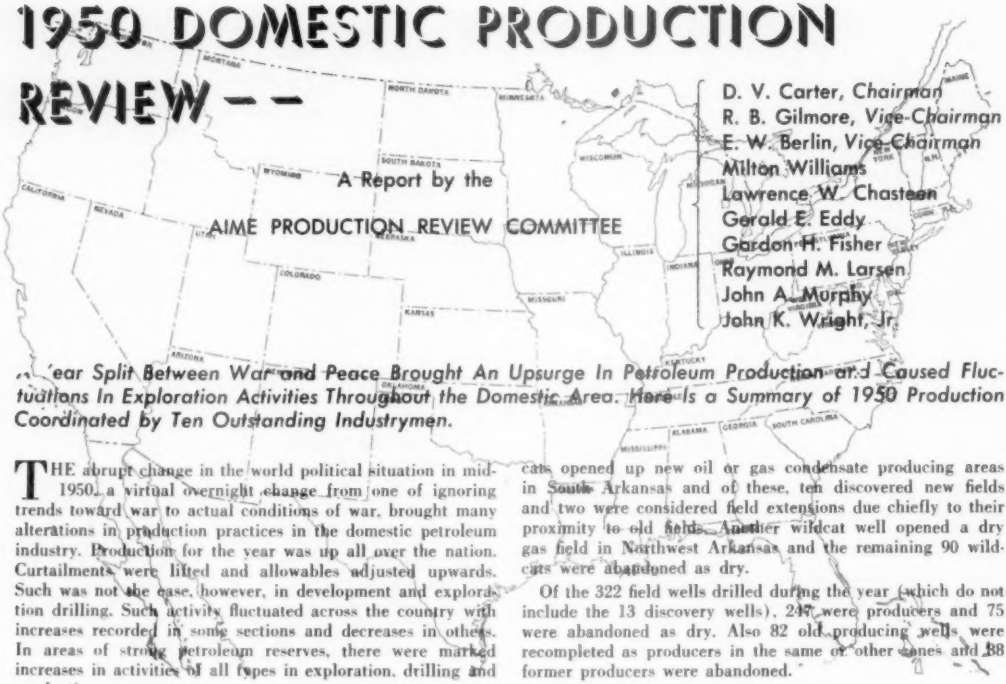


FIG. 4 — NECESSARY DEPTHS TO PREVENT LOSS TO FORMATION WITH PROPANE STORAGE.

1950 DOMESTIC PRODUCTION REVIEW - -



A Report by the

AIME PRODUCTION REVIEW COMMITTEE

D. V. Carter, *Chairman*
R. B. Gilmore, *Vice-Chairman*
E. W. Berlin, *Vice-Chairman*
Milton Williams
Lawrence W. Chasteen
Gerald E. Eddy
Gordon H. Fisher
Raymond M. Larsen
John A. Murphy
John K. Wright, Jr.

A Year Split Between War and Peace Brought An Upsurge In Petroleum Production and Caused Fluctuations In Exploration Activities Throughout the Domestic Area. Here Is a Summary of 1950 Production Coordinated by Ten Outstanding Industrymen.

THE abrupt change in the world political situation in mid-1950, a virtual overnight change from one of ignoring trends toward war to actual conditions of war, brought many alterations in production practices in the domestic petroleum industry. Production for the year was up all over the nation. Curtailments were lifted and allowables adjusted upwards. Such was not the case, however, in development and exploration drilling. Such activity fluctuated across the country with increases recorded in some sections and decreases in others. In areas of strong petroleum reserves, there were marked increases in activities of all types in exploration, drilling and production.

There follows a summary of activity in the various sections of the United States. The data presented here were gathered by members of the AIME Production Review Committee and were reported upon in greater detail at the AIME Annual Meeting in St. Louis, Mo., Feb. 22.

ARKANSAS

Production

Cumulative oil and condensate production in Arkansas at the end of 1950 totalled 815,758,477 bbl. During the year the output of oil plus condensate totalled 30,840,007 bbl or 1,054,594 bbl more than the annual production of 1949. Runs to stills during the year amounted to 20,448,082 bbl or an increase of 2,721,829 bbl over 1949, and the intake volume of the gasoline plants increased from 59,752,686 cu ft in 1949 to 65,292,690 cu ft in 1950. Dry gas production in Northwest Arkansas increased from 6,900,678 cu ft in 1949 to 7,802,827 cu ft in 1950.

Exploration and Drilling

Geophysical exploration in Arkansas was confined almost entirely to the southern half of the state and decreased from 610 crew weeks in 1949 to 467 crew weeks in 1950. About 98 per cent of the drilling activity in Arkansas during 1950 was confined to the southern half of the state and only 2 per cent to the northern half. A total of 425 wells were drilled for oil and gas during the year, representing an increase of 66 wells over the number drilled in 1949. The 425 wells consisted of 103 wildcats and 322 field wells. Twelve of the wildcats opened up new oil or gas condensate producing areas in South Arkansas and of these, ten discovered new fields and two were considered field extensions due chiefly to their proximity to old fields. Another wildcat well opened a dry gas field in Northwest Arkansas and the remaining 90 wildcats were abandoned as dry.

Of the 322 field wells drilled during the year (which do not include the 13 discovery wells), 247 were producers and 75 were abandoned as dry. Also 82 old producing wells were recompleted as producers in the same or other zones and 88 former producers were abandoned.

Secondary Recovery Projects

Excellent results were obtained by secondary methods of recovery in the oil and gas fields of South Arkansas. These methods proved successful in the following reservoirs: Haynesville, Lisbon, Magnolia, McKamie-Patton, Midway, Schuler, Stephens and Wesson.

CALIFORNIA

Crude oil operations for 1950 could best be described as reversing the trends of 1949 from a declining production rate to an increased production rate. At the beginning of 1949, the outlook was one of overproduction with the threat of curtailment, while by the end of 1950 a period of expansion, both in drilling and production, was anticipated. The principal concern among crude oil producers was the threat of material and manpower shortages which might result from defense preparations.

Crude Oil Production

Production at the beginning of 1950 was 866,969 B/D, which was approximately the rate in late 1945 and early 1946. After 1946, production steadily increased to a peak of 954,000 B/D realized in November, 1948. This rate was the all-time peak for the state until it was later broken by a production of 963,400 B/D in December, 1950. This new peak was especially significant because Elk Hills, which produced at the rate of 65,000 B/D in World War II, was practically shut in. In addition, there was also an estimated shut-in capacity of 18,000 B/D in other fields.

For the first four months of 1950, the state continued the decline started in early 1949 and reached a minimum of

857,439 B/D in April. In May, production began a rapid rise to the peak reached in December of 963,418 B/D.

Development

During 1950, some 1,262 oil wells and 46 gas wells were reported completed. Their total initial production rate was 262,800 B/D. The new well completion rate reached a peak at the end of the year with 122 oil wells completed in December. The 1950 completion figure represents a decrease of 461 under the 1949 development figure. However, initial production increased some 25,800 B/D. Gas well completions increased by 11 over the 1949 number.

Exploration and Discoveries

During 1950, a total of 489 exploratory wells were drilled as compared to 588 in 1949, representing a 17 per cent decrease. New field wildcats totaled 277 in 1950 as compared to 340 in 1949. A total of 11 new oil fields and two gas fields are credited as discoveries in California for 1950. In addition to the new fields, seven new pools and two important extensions were made. Although the list of discoveries is long, there were no major additions made to reserves. Based on the data available, it is doubtful if California's reserve position will hold its own for 1950.

Exploratory Activity in Other Pacific Coast Areas

Exploration work on the Pacific Coast in areas outside California was highlighted by the shifting of activity from the Pacific Northwest to the Great Basin area of Nevada. Some 15 companies were actively engaged in geologic work in Nevada and by year's end more than one million acres of Government land were under lease. One well was abandoned at 10,314 ft and two other wells were drilled without success in 1950. At year's end, two more wells were being drilled, one in Clark County and the other in White Pine County.

In Arizona, nine wells were drilled and were either abandoned or idle by December 31. Two wells were drilled in Oregon but neither were successful although reports of gas showings were made from a well drilled in Lake County. In Washington, drilling activities ceased with the abandonment, after test, of Union Oil Co.'s State No. 3 in Grays Harbor County. One well spudded in Clallum County on the Olympic Peninsula in 1950 but was idle at the end of the year.

Petroleum Supply and Demand

The Pacific Coast total petroleum supply and demand situation underwent a sharp change in 1950 compared with 1949. On the basis of data published by the Bureau of Mines for the first 11 months, total petroleum supply declined about 2 per cent to around 990,000 B/D from 1,010,000 B/D in 1949. Total demand, on the other hand, increased to 1,070,000 B/D, a gain of about 11.5 per cent over the year earlier level of 960,000 B/D. As a result of these diverse trends, total stocks of all oils on the Pacific Coast declined about 28,500,000 bbl for the year which was in marked contrast to the increase of 18,400,000 bbl in 1949.

Contributing to the over-all improvement were gains of 9.7 per cent in total demand for gasoline, 6.25 per cent in stove and diesel oil, and 15.1 per cent in fuel oil. An important factor in the gain in fuel oil demand was the shipment of more than 40,000 B/D to the East Coast. This eastward movement of fuel oil ended in the fourth quarter of 1950.

The year proved to be one of sharp improvement over the unhealthy statistical position which had been built up previously. Through the curtailment of crude oil production and refinery activity, inventories were reduced to levels generally considered to be near the economic minimum in relation to the rate of demand. A reversal of both supply and demand trends occurred during the year, becoming evident in the second quarter. In large measure, the improvement in the position of the Pacific Coast petroleum industry reflects the stimulus of the Korean War and the mobilization program. In this connection, it is interesting to note that the Pacific Coast petroleum industry is supplying more than one-half the total United States military petroleum requirements.

ILLINOIS

In Illinois 2,894 wells were drilled for oil and gas in 1950 as compared with 2,742 in 1949, an increase of 5.5 per cent. This number includes 830 wildcat wells which discovered 25 new pools and 77 extensions to pools. There were no major pools among the 25 discovered in 1950.

An outstanding event in the oil industry of Illinois was the beginning of water flooding in the Salem Pool, Marion County, under a voluntary unit operating agreement. Up to the end of 1950, the Salem Pool had produced approximately 216 million bbl of oil in 12 years and it is expected to produce another 200 million bbl by flooding. Other Illinois water flooding operations are progressing favorably. Total oil production in Illinois in 1950 was 62,123,000 bbl (preliminary figure) valued at approximately $172,081,000. This represents a decline in production of approximately 4 per cent from the 64,583,000 bbl produced in 1949.

INDIANA

A total of 1,527 wells drilled for oil and gas were completed in Indiana in 1950 as compared with 1,288 in 1949, an increase of 18 per cent. Total oil production in 1950 was some 10,702,683 bbl as compared with 9,734,000 bbl in 1949, an increase of 10 per cent. Wildcat drilling amounted to about one-third of the total drilling. Of these 504 wells, 28 discovered new pools; 18 new plays; 26 extensions; and 432 were dry holes. Most of the wells drilled were in Southwestern Indiana.

KANSAS

Kansas operators posted new record highs in both the number of wildcat wells and total well completions during 1950. Wildcat drilling increased by a phenomenal 56 per cent over 1949 to a total of 816 wells. Total well completions were up 20 per cent to an all-time high of 4,077. Oil production increased by 7 per cent to slightly over 107 million bbl, the second largest annual production recorded. Total footage drilled was nearly 12.75 million ft, an increase of 19 per cent over the previous record 1949 figure.

The development of proven fields increased about 14 per cent over 1949. Drilling continued at a rapid rate in the Kraft-Prusa, Morel, Trapp, Silica, El Dorado, and Berland fields. Some 373 new gas wells were reported drilled in the Hugoton Gas Field. Permits were granted for 61 new waterflooding projects, chiefly in the East Kansas stripper area. It is estimated that more than 10 per cent of the current oil production in Kansas is from secondary recovery operations. In spite of the sharp increase in the number of exploratory wells drilled, the success ratio declined only slightly, from 19.8 per cent to 17.4 per cent for 1950. One of the outstanding discoveries of the year was the Fall Creek Field in Sumner County. The discovery well was complete in August with a calculated potential of 6,226 B/D from the Simpson dolomite. Four wells had been completed in this field at year's end. Exploratory activity in the Central Platform area accounted for the majority of the discoveries during 1950.

KENTUCKY

Kentucky produced 9,205,707 bbl of oil during the first 11 months of 1950, and with December yet to be calculated at this writing, it is expected that the figure will exceed the 10,000,000 bbl mark for the second time in the state's history. In addition, 70 billion cu ft of gas was produced during the year, of which 95 per cent came from the Big Sandy Gas Field

of Eastern Kentucky. During the year, 1,226 wells were drilled of which 524 were oil wells, 193 gas wells and 509 dry holes.

The most spectacular development in Western Kentucky during 1950 was in the Zion North Pool of Henderson County where 48 oil wells out of 59 wells drilled produced oil from the McClosky limestone. The total initial production of the 48 oil wells amounted to more than 12,000 B/D. The largest operations were in the Morganfield South in Union County where 66 wells were drilled, of which 57 were oil wells. In the Guffie Pool in McLean County, 48 oil wells and 12 dry holes were drilled. As of November, daily pipe line runs were 1,700 B/D. The Griffith Pool in Davies County had the fourth largest number of operations with 35 oil wells, three gas wells and 20 dry holes with pipe line runs of 705 B/D as of the same date. The only new oil development in Eastern Kentucky was small extensions of the Weir Oil Fields of Elliott County on the west flank of Paint Creek Uplift and extensions of the Corniferous White Creek Pool in Wolfe and Powell counties.

LOUISIANA

1950 witnessed an increase of 43 active wells over 1949 in Louisiana. The active wells include all wells drilled and drilling prior to January 1, 1951. There were 2,631 field wells and 331 exploratory wells drilled resulting in a total of 2,962 active wells for the year. At the end of the year, 174 field wells and 71 wildcat wells were drilling.

In comparing the number of wells drilled in North Louisiana and South Louisiana it is found that there were more field and wildcat wells drilled in the northern part of the state. This resulted in a greater number of successful field wells in North Louisiana but not of successful wildcats. In Northern Louisiana's two districts there were 1,367 wells drilled and of this number 1,220 were field wells, 709 oil, 256 gas, 255 dry holes and 147 wildcat wells. In South Louisiana there were 1,083 wells drilled. Wells drilled in unproven areas resulted in the discovery of 30 new fields, 23 oil and seven gas. Four of the 30 new discoveries may develop into major fields. They are Cox Bay, Romere Pass, Glenmore and Unionville.

Production

Production of oil and gas in Louisiana during 1950 increased in comparison to 1949 figures. Oil production (including condensate) showed a net gain of 15,786,051 bbl, amounting to a 7.98 per cent increase. Gas production, both natural and that produced in conjunction with oil, increased by 93,946,807 cu ft, a 9.16 per cent gain over 1949 gas production.

Offshore Activity

The number of successful wells completed in the Gulf of Mexico during the year totaled 47, as compared with a total of 44 in 1949. During 1950, 98 wells were drilled, 37 completed as oil wells, 10 as gas wells, 34 abandoned and 17 drilling at the end of the year. The Bay Marchand area showed the greatest increase in activity over 1949. A total of 25 wells were completed, 18 as oil, one as gas and six abandoned.

MICHIGAN

Estimated oil production for Michigan for 1950 was 15,800,000 bbl. This figure compares disfavorably with the 1949 total of 16,503,473 bbl. Estimated dry natural gas production is 10 billion cu ft, a decrease of approximately 4.5 billion cu ft from 1949 production. However, this decrease from domestic production was more than offset by increases in imported gas both to the markets and into underground storage. It is estimated that during the year 90 billion cu ft were imported.

During the year, 901 oil and gas permits were issued. Of the 890 completions, it is estimated that 325 were oil wells, 75 were gas wells and 490 were dry holes. Total footage drilled for the year is estimated at 2,150,000 ft of which probably 800,000 ft was wildcat drilling.

Sixteen new fields, six new pays and seven extensions were discovered during the year. Of the new fields, Cannon Creek was probably the most important. Seventeen wells have been drilled, proving up 2,720 acres, and the field is not as yet defined. The Howell-Salina gas field with 16 wells and an area of 2,600 acres during the year produced 3.75 billion cu ft.

MISSISSIPPI

In 1950, there was a further decrease in the development drilling in Mississippi with only 177 development wells drilled as compared with 218 drilled in 1949. Of these 177 wells, 127 were successfully completed as producers. However, exploratory drilling was on the upswing during 1950 with 128 wildcat wells being drilled compared to 117 in 1949. These wildcat wells discovered eight new producible fields. The year 1950 saw 305 wells drilled in Mississippi. During the period, the state produced approximately 38,500,000 bbl of oil and condensate from 44 oil and gas fields. This figure brings the cumulative total for the state since August, 1939, when oil was first discovered in Mississippi, to some 285,300,000 bbl of oil and condensate.

MISSOURI

A total of 27 wells were completed in Missouri during 1950, an increase of five over the 1949 figure. Of these, two were completed as oil wells and 10 as gas wells. Seven exploratory wells were reported drilled during 1950, all of which were dry. Oil production increased slightly to about 36,000 bbl for the year.

NEBRASKA

Drilling activity in Nebraska has increased rapidly since the discovery of the Gurley Field in Cheyenne County in 1949. Total completions were up from 27 to 171 wells while wildcat wells increased from 18 to 82, of which 13 were successfully completed as oil or gas producers. Crude production for 1950 was approximately 1.25 million bbl as compared with 330,000 bbl for 1949.

Exploratory drilling resulted in the discovery of eight new oil and gas fields in Western Nebraska during 1950. Six of these fields are within a radius of about 10 miles of Sidney, Cheyenne County. One new gas field is located near Big Springs, Duell County, about 45 miles east of Sidney, and a new oil field is located near Alma, Harlan County, near the Kansas border.

NEW MEXICO

New Mexico produced approximately 47,300,000 bbl of oil during 1950, an average of slightly less than 130,000 B/D. There were approximately 6,100 wells at the end of the year. There were 607 wells drilled in the state during the year, of which 484 were completed as oil or gas producers. Seventy-nine of the wells drilled were wildcats and 23 of these were completed as oil or gas wells. Cumulative production from New Mexico at the end of 1950 was approximately 681,000,000 bbl with estimated reserves of approximately 610,000,000 bbl. There were 16 discoveries in the state during 1950, including new pays in previously producing areas.

NEW YORK

Oil production in New York for 1950 is estimated to be 4,130,000 bbl, representing an approximate decrease of 6.1 per cent from 1949 production figures. During the year, 700 field wells were drilled in all fields with 567 completions in the Allegany Field. This figure represents a decrease of 20

per cent under the drilling program of 1949. This decrease in drilling activity is probably due to the price of oil and to drilling only in proven areas with very little wildcat drilling being carried on. The total number of producing wells in New York, all stripper type, is in the neighborhood of 23,500.

The Medina and Oriskany gas production in New York for 1950 is estimated at 4 billion cu ft.

OHIO

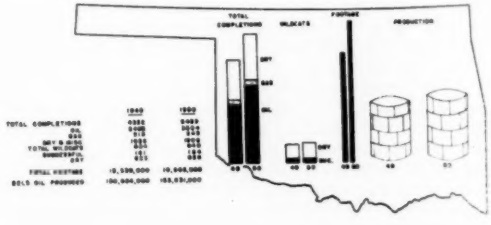
Total number of wells in Ohio during 1950 was 1,141, of which 284 were gas wells, 282 oil wells, 100 combination wells, and 475 dry holes. Total gas production amounted to 143,833 cu ft and oil production totaled 10,328 bbl for the year. No new gas pools of size were discovered during the year and drilling in the gas areas dropped off. The principal oil development during the year took place in New Castle township, Coshocton County, in the Clinton Sand.

OKLAHOMA

Activity in Oklahoma continued at an accelerated rate during 1950. Well completions were up 25 per cent over 1949 to 5,459, the largest number since 1923. The number of wildcat wells increased only about 5 per cent over 1949 to a total of 840, about 22 per cent of which were successfully completed as oil or gas wells. Total footage of drilled wells was up nearly 30 per cent to what probably is an all-time high of nearly 20 million ft. Crude production during the year increased to a new 12-year peak of more than 163 million bbl, largely as a result of increased allowables and new development.

Most of the sharp increase in drilling during the year resulted from the accelerated development of such proven fields as Elk City and Ringwood in Western Oklahoma and the Golden Trend, Palacine and Velma-Sholem Alechem areas in South Central Oklahoma.

Exploratory activity in the western part of the state was disappointing. Several deep tests were drilled on presumed seismograph highs in the western part of the Anadarko basin but all were dry. Probably the most important discoveries of the year were located in the south and south central parts of the state. Of extreme importance is the discovery and extension of deep Springer (Pennsylvania) sand production in the Ara, North Milroy, Fox-Graham, and Knox areas of Stephens, Carter, and Grady counties. Several narrow but rich bands of Springer production have been encountered, generally off the flanks of proven fields producing from shallower zones. One such band appears to lie southeast of Velma and along the north flank of the Fox-Milroy high. Two recent and probably very significant discoveries were made in Love County, in the Marietta basin. Production was encountered in one of the Deese sands (Pennsylvanian) in both wells, located about two miles apart, which suggests the possibility that one large field may have been discovered. Exploratory drilling continued at a high rate in the central and north-central parts of the state, resulting in the discovery of a large number of relatively small fields, chiefly in Pennsylvanian sands. The development of the Hydrafrac process, which has enabled commercial completion to be made in many of the tighter sands which formerly were passed up, has stimulated the development of this area.



OKLAHOMA

PENNSYLVANIA

There was a slight increase in oil production in Pennsylvania during 1950 due to improved market conditions, but a decline of more than 10 per cent in drilling activities conducted in connection with secondary recovery operations, which acount for the bulk of the oil production in Pennsylvania. No new oil pool was discovered. In the shallowed sand gas territory, less drilling was carried out in 1950 than in 1949. There were some extensions of oil pools and several new discoveries but none of these gave promise of developing into pools of significant size. Thirty-four new wells were completed to the deeper horizons (into and below the Onondaga) in 1950, as compared with 27 in 1949. Of these, two completed for gas storage purposes. Of the remainder, 21 were gas wells and 11 were dry holes.

The oustanding event of 1950 was the discovery of another major Oriskany sand gas pool in North Central Pennsylvania early in the year. By the end of 1950, twelve producing wells and three dry holes had been completed and 42 wells were drilling. The pool was producing at the rate of about 150 MMcf per day.

ROCKY MOUNTAIN AREA

Oil production from Colorado, Montana, Utah and Wyoming totaled more than 94,000,000 bbl in 1950, an overall high. Wyoming was responsible for most of the increase. Production in January was at the rate of 240,000 B/D and in December it amounted to 298,000 B/D.

Five wildcat wells in Idaho were dry and one deep test was still drilling. Nevada had four dry holes, one at Meridian being 10,314 ft deep. Upon completion of this test late in the year, the drilling equipment was moved to Hayden Creek, White Pi[illegible] County. Several unsuccessful wells also were drilled in [illegible]orth and South Dakota.

Colorado

Oil production in 1950 was 23,140,000 bbl or 440,000 bbl less than in 1949. About 42 oil wells and 12 gas wells were drilled as compared with 55 plus four in 1949.

Montana

Oil production in 1950 in Montana totalled 8,279,000 bbl which was 845,000 bbl less than in 1949 and 1,000,000 bbl less than the 1949 maximum. Production varied from 20,000 B/D in January to 24,000 B/D in December. The only apparent new field discoveries were at West Sumatra and Northwest Sumatra in Rosebud County. Notable extensions or new pools were found east and southwest of the Pondera Field.

Utah

Oil production in Utah during 1950 totaled 1,208,000 bbl or 572,000 bbl more than in 1949. Three oil wells were completed at Ashley Creek in 1950 and with 30 wells in the Weber sand, development is about complete unless other formations warrant separate drilling. A new oil discovery was made at Gusher but initial production at a depth of 9,757 ft in the Green River formation was only 20-35 B/D.

Wyoming

Oil production in 1950 in Wyoming established a record high of 61,700,000 bbl which was 13,385,000 bbl more than in 1949 and 7,000,000 bbl more than in 1948, the previous high year. New fields were discovered at Bonanza, Deep

Creek (gas), Deer Creek, South Glenrock, Longs Creek (gas), Happy Springs, Meadow Creek, Nowood, Slick Creek, and Clareton.

SOUTHERN STATES

Alabama

During 1950, there were 46 wells drilled in various parts of Alabama, 18 of which produced oil, one produced dry gas, and 27 were dry holes. There were 22 wildcat wells completed in 12 counties during the year, two of which resulted in new discoveries of reservoirs for the state. Most of the wildcat drilling was in the southwestern part of the state. Twenty-four field wells were completed with 17 producing oil and seven were dry holes. Alabama produced approximately 743,000 bbl of oil during the year, bringing the cumulative total for the state to approximately 2,733,000 bbl.

Florida

There were 14 wells drilled in Florida during 1950, eleven wildcats which were all dry and three field wells, one of which was completed as a producer. The 11 wildcat wells were drilled in nine counties and the three development wells were all in the Sunniland Field. There are now 12 wells producing in the lone Sunniland Field which produced approximately 476,000 bbl of oil during 1950, bringing the cumulative total for the state and the field to approximately 1,553,000 bbl.

Georgia

Georgia had five wells drilled during 1950, all of which proved to be dry holes. There were two wells drilled in Seminole County and one each in Calhoun, Decatur and Heard counties. These five wells bring Georgia's total wildcats since 1938 to 46 and all these wells have been dry.

TENNESSEE

An encouraging upsurge in drilling activity in Tennessee during the early months of 1950 was followed by a lull during the summer and early fall but as the year closed the deep tests started at the first of the year continued to drill and new tests are drilling or slated to start in the immediate future. Gas production during 1950 was slightly more than 88 MMcf, a decided drop from production of 137 MMcf during 1949.

TEXAS

East and East Central Texas

For the most part, new discoveries in the East Texas area were small and disappointing. Most of the discoveries were in the Woodbine and Sub-Clarkville sands. Of the new sand pools, the Woodbine Reservoir in the Pine Mills Field which previously has produced only from the Sub-Clarkville sand is of some interest. Exploratory wells drilled in 1950 amounted to 19 oil, six gas or gas condensate wells and 198 dry holes for a success percentage of 11.2.

North Texas

Approximately 3,020 wells were completed in North Texas during 1950, of which about 1,660 were completed as oil or gas wells. Six hundred and seven wildcats were drilled, of which 108 were completed as oil or gas wells. Production amounted to approximately 53,300,000 bbl from some 23,000 producing wells. Cumulative production in the area at the end of 1950 was in excess of 1,151,000,000 bbl. Some 60 new pools were reported during the year, none of which appear at this time to be of very great importance.

North Central Texas

This area produced slightly more than 25.5 million bbl of oil during 1950 or a daily average of 70,000 bbl which was approximately 3,000 B/D greater than 1949. At the end of the year there were more than 8,600 producing wells and the total cumulative production to January 1, 1951, was more than 502,000,000 bbl. During the year some 2,040 wells were drilled of which about 1,000 were completed as oil or gas wells.

Panhandle Area

During 1950, the Texas Panhandle area saw some 890 wells drilled, of which 814 were completed as oil or gas wells. Twenty-four of the wells were drilled as wildcats, resulting in the completion of one oil well and two gas wells. At the end of the year there were some 7,900 wells producing in the area. Production during 1950 amounted to some 33,120,000 bbl or a little more less than 91,000 B/D and very nearly the same as during 1949. Cumulative production to the end of 1950 approximated 696,000,000 bbl.

South Texas

The Wilcox and Frio-Vicksburg trends received about equal attention in exploratory activities during 1950 in the South Texas area. The Portilla Field, San Patricio County, appears to be a discovery of major importance. Several Frio and Vicksburg sands produce oil in this field. Possibly the largest Wilcox discovery in this area in recent years is the Helen Gohlke Field in DeWitt and Victoria counties. Exploratory wells drilled during the year amounted to 114 oil, 56 gas or gas condensate, and 455 dry holes for a success percentage of 27.1.

South Central Texas

No discovery of apparent major importance was made in 1950 in the South Central Texas area although the successful completion of a deep Edwards Limestone oil well in Atascosa County may bring renewed interest to the Charlotte-Imogene trend in that area. Wildcatting was scattered throughout 19 of the 30 counties in the area. Of the exploratory wells drilled 14 were oil wells, four were gas or gas condensate and 189 were dry holes for a success percentage of 8.7.

Upper Gulf Coast Area

Although some fields of potential importance were discovered during 1950, the results of exploratory drilling in the Upper Gulf Coast were generally disappointing. Possibly the best of the year's discoveries was the Nona Mills Field in Hardin County. Other discoveries of interest were the Rose City Field, Orange County; West Hamshire Field, Jefferson County (producing gas); and the Trinity Bay Field, Chambers County. Of the exploratory wells drilled 75 were oil wells, 11 were gas or gas condensate and 252 were dry holes.

West Texas

Slightly more than 5,000 wells were drilled in the West Texas area during 1950, of which approximately 4,130 were completed as oil or gas wells. About 670 were drilled as wildcats, of which some 116 were completed as oil or gas wells. The number of producing wells at the end of the year was approximately 30,300. Production amounted to slightly more than 284,500,000 bbl or an average of more than 779,000 B/D. Cumulative production for the area to Jan. 1, 1951, was slightly more than 2,915,000,000 bbl.

Activity continued in the Canyon Reef fields in Scurry, Kent and Borden counties. More than 1,300 wells had been completed by the end of the year. An important development was the Sweetie Peck discovery in Midland County. Some 19 wells were producing at year's end. Approximately 130 fields were discovered in West Texas during 1950 including the new zones brought into production on previously productive structures. ★ ★ ★

Technical Note 67——

THE CALCULATION OF WATER RESISTIVITIES FROM CHEMICAL ANALYSES

H. F. DUNLAP, MEMBER AIME, AND **R. R. HAWTHORNE,** JUNIOR MEMBER AIME, ATLANTIC REFINING CO., DALLAS, TEX.

ABSTRACT

A method of calculating formation water resistivities from chemical analyses is presented which is somewhat faster and more accurate than previously described methods. For 26 formation water samples taken from wells in the Texas Gulf Coast, the average deviation of calculated from measured water resistivities was 3.3 per cent, with an average bias of +1.1 per cent in the calculated values. This compares with average deviations of 4.6 per cent and 7.8 per cent, with corresponding average biases of +3.2 per cent and –6.3 per cent, for the two methods previously described in the literature. All three methods are sufficiently accurate for most purposes; the main advantage of the method presented is its speed and convenience.

DISCUSSION

It is frequently desirable to calculate the formation water resistivity from the chemical analysis of the water, as for example, in electric log interpretation. Two methods have previously been given in the literature[1,2] for accomplishing this. Both methods require that the chemical analysis be given in the Palmer[3] system, as primary and secondary alkalinity and salinity. This conversion of the values of the ppm of the various ions to primary and secondary salinity and alkalinity is time consuming, and many laboratories report only the concentrations of the various ions in parts per million. However, all laboratories report the individual ionic concentrations, whether or not the Palmer system of reporting is also used. Hence it was thought that a method that would permit resistivity calculations directly from these data would be useful.

Table I — Conversion Factors for Calculating Water Resistivity

Na ppm x 1.00 = N_1	Equivalent ppm *NaCl.*
Ca ppm x .95 = N_2	Equivalent ppm *NaCl.*
Mg ppm x 2.00 = N_3	Equivalent ppm *NaCl.*
Cl ppm x 1.00 = N_4	Equivalent ppm *NaCl.*
SO_4 ppm x .50 = N_5	Equivalent ppm *NaCl.*
HCO_3 ppm x .27 = N_6	Equivalent ppm *NaCl.*
CO_3 ppm x 1.26 = N_7	Equivalent ppm *NaCl.*
ΣNi =	Total Equivalent ppm *NaCl.*

In the method developed, the various ions reported in the chemical analysis are converted to an equivalent amount of *NaCl*. The sum of the various contributions to the *NaCl* (actual or equivalent) can then be used in conjunction with a plot of *NaCl* concentration versus resistivity to obtain the resistivity of the solution in question. The conversion factors used in this process are shown in Table I and the resistivity vs. *NaCl* saturation plot (I.C.T. data) in Fig. 1. An example of a typical calculation is shown in Table II, together with the measured resistivity.

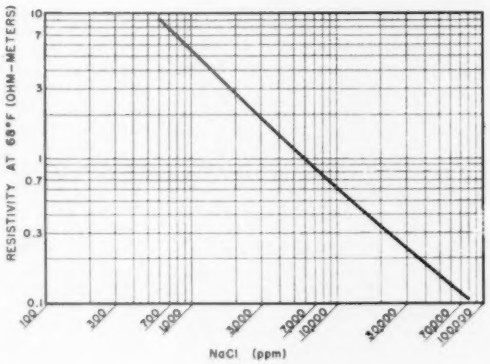


FIG. 1 — *NaCl* CONCENTRATION VS. RESISTIVITY.

These conversion factors for the various ions were obtained by measuring the resistivities of a number of simple solutions containing only two types of ions, one of which was always either *Na+* or *Cl–*. Although for dilute solutions of most ions

Continued on Page 7, Section 2

Table II — Example of Method Applied to a Frio Water from the Aransas Field, San Patricio County, Texas

Ionic Constituent	Concentration PPM	Conversion Factor	Equivalent Concentration of *NaCl* (PPM)
Na (calculated)	21,899	1.00	21,899
Ca	2,449	.95	2,325
Mg	382	2.00	764
Cl	38,292	1.00	38,292
SO_4	381	.50	191
HCO_3	1,098	.27	296
CO_3	0	1.26	0

Total Equivalent *NaCl* concentration = 63,767
Calculated Resistivity (using Fig. 1) .126Ω*M*
Measured Resistivity .131Ω*M*
Error = –3.8 per cent

Oil in Kuwait and the Persian Gulf

Reported By
John Clayton Jacobs, Jr.
North Texas Section

F. E. Hatfield, manager of exploitation of the Fort Worth Division of the Gulf Oil Corp., outlined last month highlights of a recent trip through the Middle East oil fields. His remarks were directed to members of the North Texas Section in meeting at Fort Worth.

Known reserves of the Middle East are, Hatfield pointed out, enormous. Estimates are in the order of 40 billion or more bbl proven reserves and potential reserves of 100 to 150 billion bbl, or about one-half the world's supply. For comparison, United States reserves are estimated at 25 to 30 billion bbl proven and 50 billion bbl potential. Current Persian Gulf daily production, averaging 5,000 bbl per well daily, is more than 1,800,000 bbl, or 18 per cent of the world's total of 10,000,000 B/D. Some time next year, if 500,000 B/D are taken from Kuwait, as it is rumored, production may reach 2 million B/D and in 1952 and 1953, with Middle East pipe line completed, production could reach 2.5 million B/D.

The largest and oldest producing company is Anglo-Iranian. Although oil seeps in the Middle East have been known since Biblical times, the forerunner of Anglo-Iranian, the D'arcy Petroleum Co., discovered the first oil in the Persian Gulf in the Sulaiman Field in 1908. The concession taken by D'arcy in 1902 cost $20,000. Anglo-Iranian's daily production in Iran is about 625,000 bbl and it has a refining capacity at Abadan, Iran, of 550,000 B/D.

Commercial oil was next found in Iraq by the Iraq Oil Co. in 1927, which resulted in building the first trans-desert pipe line in 1934, a double 12-in., to the Mediterranean Sea. In 1948, one of these lines which went to Haifa in Palestine was cut off by the Arab Iraq government and this line is still out of service. Later a 16-in. line was laid from Kirkuk to Tripoli in the Lebanon and Bechtel is now beginning another 30-in. line from Kirkuk to Banias, Syria, a distance of about 560 miles, which will handle around 275,000 B/D and capacity of all Iraq Petroleum Co. lines would then be more than 500,000 B/D in 1952 and 1953. Present production is just under 170,000 B/D.

The second largest producing area is Aramco's series of fields in Saudi Arabia near the Gulf discovered, just across a narrow strait from Bahrein Island, in 1937. Since then, seven fields have been found in all, the largest, Abquaiq, producing around 525,000 B/D from 50 wells. Within the last year and a half, a 140,000-bbl refinery has been built by Aramco at Ras Tanura on the Gulf and the new 30-in., 1,000-mile pipe line from Abquaiq Field to the Mediterranean at the ancient city of Sidon, Lebanon, was completed December 1 at a cost of $200,000,000. These facilities will handle 315,000 B/D and save about $.18 per barrel toll through the Suez Canal as well as tanker costs of $.65 to $.70 per barrel for the 3,200-mile trip. Aramco's production is now more than 640,000 B/D.

The Bahrein Island Field, about 25 miles from the Arabian mainland, was discovered in 1932 and produces something less than 30,000 B/D.

Now something about Kuwait and the Burgan Field, the world's largest oil field. After a geological and geophysical survey by the joint owners of the concession — Gulf and Anglo-Iranian — which disclosed some asphalt seeps and evidence of structure, the first well begun in May, 1936, was dry at about 8,000 ft. Oil was encountered in Burgan No. 1 in February, 1938. Drilling went on slowly until nine wells were completed in 1942 when, due to the war, it was thought advisable to plug them off and shut everything down. In late 1945, the wells were cleaned out, drilling of additional wells began and the first tanker was loaded in June, 1946. At present about 100 wells are completed, but only about 65 are used as producers because of the fact that the highest gravity oil, around 31°, comes from the highest part of the structure.

The pay is sand, Middle Cretaceous, lying in three to four zones between 3,500 ft and 4,800 ft with as much as 550 ft of net thickness. The wells are practically all dual zone, completed in the conventional way. The reservoir contains approximately 60,000 acres and is about seven by 14 miles in area. Spacing is one well to 600 acres. More than 240,000,000 bbl of oil have been withdrawn with no discernible drop in bottom hole pressure.

A brief look at the surface installations which are typical of the large Middle East fields reveals that there are five gathering stations which cost, erected, about $1,600,000 each, handling from 40,000 to 175,000 B/D. Horizontal separators are used with four to seven stages of separation. There are two 50,000-bbl receiving tanks and a gas engine-driven pumping installation to deliver oil to the tank farm about 11 miles away. At the tank farm there are 21 big storage tanks where the oil is gauged and fiscalized for government royalty purposes.

The oil is then gravitated five miles to the oil loading dock on the Persian Gulf. This installation can load, under ideal circumstances, as much as 700,000 B/D from the new oil and cargo jetty, finished late in 1949. On the coast near the jetty there is also a 25,000-bbl refinery which was placed in operation in October, 1949, producing kerosene, gasoline, diesel and bunker fuel for use in the country and fuel for ships calling at Mena El Ahmadi. A steam electric station and sea water vacuum distillation plant, to produce 15,000 kilowatts and turn out 10,000 B/D fresh water from sea water, is now completed.

The Ahmadi headquarters camp is up on the hill near the tank farm. There are about 260 permanent houses for British and Americans besides several hundred temporary houses, general office, shops, warehouse, cooling and heating plant, mess halls, barracks, etc.

Some 60 members and guests of the North Texas Section heard Hatfield's description of Middle East operations. R. S. Christie introduced the speaker.

★ ★ ★

Operating Conditions in South America

Reported By

W. G. Paul, Jr.

Pacific Junior Group

William H. Sargent, recently returned from an extended tour through South America in his capacity as head of foreign sales for Sargent Engineering Corp., spoke to members of the Junior Section of the Pacific Petroleum Chapter in Downey, Calif., last month.

Sargent prefaced his discussion, which depicted his travels through South America, with some general comments on what the "gringo" can expect. He described the Latin American countries as a land of many extremes. On the one hand is found the most modern garbage disposal system in the world, while, at the same time, there is no sewage system, and sewage is allowed to run down the streets. At Lake Maracaibo, Venezuela, intensive modern oil drilling and production proceeds directly over the water, while the natives live in primitive huts along the shore.

This Maracaibo development is tremendously impressive. In the beginning, one company leased the shore rights and began drilling. A second company came in on the offshore rights, and a third leased the center of the lake. Today all three operators have producing wells, some as far as 22 miles off shore. The problem of establishing and maintaining a location on the lake is severe due to the high waves which can engulf and capsize boats, and because of the silty bottom of the lake which seemingly swallows up foundations like quick sand. It is common practice to sink heavy cement pillars for corners of the derrick floor some 300 ft into the silty lake bottom without ever reaching bed rock. These pillars are allowed to settle in by placing weights upon them, as it has proven impossible to jet or drive them. In some cases, the wells are drilled in 200 ft of water which necessitates a total depth of 500 ft for the cement pillars.

Sargent noted that a majority of oil company technical personnel in South America come from the Gulf Coast or Europe. The opportunity for capable technical men is excellent, but Sargent warned against the idea of getting rich quick. He noted that the South American may appear ignorant, but that actually he is far from it. The general tendency is to welcome anyone who has something constructive to offer, but to eliminate the man who is only interested in making a dollar at the expense of the native.

For those contemplating South American visits, Sargent advises a large wardrobe of nylon clothing. While it has the disadvantage of retaining heat, it has a major advantage in that it can be washed by hand. Native washings return clothes either green or brown, depending upon whether there is moss or mud in the local river. In many cases, laundry may not be returned at all due to the native affinity for white clothing. Since the native South American is always presumed right in any dispute with a foreigner there is little recourse. Khaki clothing is always acceptable in the field and it is very seldom that a business suit would be necessary outside the major cities.

To avoid the tropical diseases which are prevalent, Sargent advised against eating anything touched by the natives. Eat only fruits or vegetables which can be peeled and avoid water and fresh milk. Every liquid should be boiled and ice should never be added. Sargent noted that in the camps of the major companies, food is flown in to avoid contamination. If a man will eat only in the company camps or in the best known eating places, he should be able to survive a South American visit without difficulty.

Sargent devoted some time to the city of Caracas, the capitol of Venezuela. This city is the center of foreign oil operation in South America and virtually every oil company has a head office there. The problem of a sales organization at Caracas is two-fold; the high cost of maintaining a man and the beauty of the city itself, which deters quite a few from traveling back to where the actual producing operation is going on. Sargent estimated that it would cost between $40,000 and $50,000 per year to station a representative in Caracas.

Sargent concluded his talk with a series of pictures on Trinidad. He described in detail the pitch lake from which the highest grade roofing tar in the world is produced. The pitch is pried in chunks from the lake's surface and trucked to a nearby refinery. After six months, the hole will have refilled itself and the same operation can be repeated again and again. ★ ★ ★

PRODUCING PROBLEMS in South America are compared with domestic ones by W. G. Paul, Jr., left, and William H. Sargent of Sargent Engineering.

Utilization of Connate Water Data

A Report From

The North Texas Study Group

The Study Group program announced by the North Texas Section in the January issue of PETROLEUM TECHNOLOGY has been inaugurated and is being enthusiastically received by those participating in the meetings. The meetings of the Dallas Group, which are held on the second and fourth Wednesdays of each month at 7:30 p.m., are attended by 40 to 60 engineers and geologists. Marshall Fagin of the *Petroleum Engineer* is in charge of the Dallas Group. The Fort Worth Group, which meets on the first and third Wednesdays of each month at 7:30 p.m. at the Fort Worth Public Library, has an attendance of 20 to 30. Paul Wiley of The Texas Co. is in charge of the Fort Worth Group.

The first meeting of the Fort Worth Group was built around a discussion of the "Derivation of the Material Balance Equation." This discussion was led by R. M. Liebrock of the Stanolind Oil and Gas Co. At the second meeting Liebrock led a discussion on "The Application of the Material Balance Equation to a Field Problem." At the third meeting discussions of "Field Data for Reservoir Engineering Studies" and "PVT Analyses" will be held under the direction of Dave Meisenheimer of The Texas Co. and Ray Ard of the Gulf Co. The third meeting was held February 21. Those attending the meetings have been polled as to their choice of program and a schedule of future programs is to be announced shortly.

The Dallas Group chose "Connate Water" as an initial discussion topic. At the first meeting the discussion, which was led by Bill McGuire of the Atlantic Refining Co., covered the "Centrifuge Method of Determining Connate Water." At the second meeting the discussion dealt with the definition and determination of connate water, and the utilization of connate water data.

Atlantic Refining's R. L. Slobod was the discussion leader. A summary of the discussion follows.

While it was generally agreed that there is a great need for data which would enable the engineer to arrive at a figure for connate water for any given reservoir, there was considerable divergence of opinion as to the exact definition of the terms connate water, interstitial water, residual water and irreducible water. Not only does this divergence exist within the petroleum engineering field, but also apparently among geologists. Whatever term is applied to the result of a laboratory test or series of tests, there must be a clear understanding on the part of everyone involved, from the laboratory technician making the tests on up to the reservoir engineer utilizing the data, of the entire scope and aim of the endeavor. The limitations of sampling, of method, of statistical analysis — all must be considered in evaluating the final result. The blind acceptance of a "per cent connate water" or "average connate water" figure should be avoided.

The various laboratory methods of obtaining capillary pressure curves and from them the irreducible water saturation of core samples were discussed. The capillary disc method, with its inherent disadvantages, seems to be the most common method used in the industry. The concensus seems to be that it is the basic method to rely upon. Other techniques, such as the centrifuge method and the evaporation method (which gives not the full capillary pressure curve but only its end point) have not been generally accepted throughout the industry.

The use of electric logs for the determination of connate water was discussed and, while opinions varied widely as to the reliability of data so obtained, it was generally agreed that the most valuable feature of these determinations lies in the fact that the measurements are made on the reservoir itself.

In regard to the upper and lower limits of reliable connate water determinations it was brought out that figures as low as 10 per cent and as high as 50 per cent have been generally accepted, but when the percentages go much higher or lower than these limits the tendency is to doubt their reliability.

Correlation of laboratory results with direct water determinations made on cores drilled with oil base mud is considered generally to be the most reliable method of checking the various laboratory techniques. Regrettably, only a relatively small amount of such correlation has been presented in the literature. ★ ★ ★

EAST TEXAS SECTION OFFICERS — The new officers and directors of the East Texas section for 1951 are, front row, L to R, W. R. Mays, vice-chairman; W. E. LaRoche, secretary-treasurer; W. W. Leonard, chairman; and P. J. Lehnhard, director. In the back row, L to R, are Directors H. L. Long, J. A. Walker, W. S. Morris, P. E. DesJardins, W. M. Jones, Bert E. Crowder, and B. F. Patterson, Jr.

Elements of Rock Bit Design

Reported By

J. E. Kastrop

Gulf Coast Section

HENRY WOODS

One of the most stimulating talks in several months was presented at the February meeting of the Gulf Coast Section at Houston, Tex. Henry Woods, assistant chief research engineer for Hughes Tool Co., Houston, gave a practical discussion of the "Elements of Rock Bit Design." Through the use of slides and demonstrations, he showed the possibilities and limitations in the design of rock bits. One of these limitations, he said, was the size of the hole which the bit was intended to drill. To enlarge one part means reducing other parts.

For emphasis, a rock bit was designed for three different formations. Based on knowledge of bit design and formation characteristics, a bit that will produce maximum results can be made. In quartzite with a compressive strength of 68,000 psi, which is considerably harder than those generally encountered in oil well drilling, it is essential that a crushing action be obtained from the teeth. A drag or scraping action would result in breaking the teeth from the cone, or they will wear more than the rock. In drilling quartzite, a pressure of at least 68,000 psi must be exerted by the teeth in contact with the formation if any fracturing is accomplished. The number, size and shape of the teeth on such a bit are determined by the load which they must carry.

In a formation of intermediate hardness, Woods showed that it was best to use a combination gouging and scraping action. The teeth must be designed to penetrate the formation and give a twist or jerk that will break the chip loose. This twist action is accomplished by swelling the apex of the cone so that it is not true rolling, and by offsetting the cone somewhat so that the bearing about which the cone turns is slightly ahead of center.

The teeth are spaced far enough apart so that the formation is not too likely to pack between them. To break up the ridges made by the teeth on the heel row, different numbers of teeth are used on each cone.

A third and perhaps extreme type of formation drilled is that of soft clay. In removing this type material, not only must the teeth penetrate the formation, but they must dig it out with a shovel action. To drill such formations, the teeth need be widely spaced to prevent balling up the bit. The use of interrupted heel teeth is desirable. Teeth should be as slim as possible without giving too much breakage. The maximum amount of tungsten carbide is put on the teeth to make it drill in zones streaked with intermittent soft and harder formations.

In designing a bit, Woods pointed out, it is necessary to know whether it is better to concentrate on increasing the rate of penetration or making more

(Continued on Page 6, Section 2)

LEON SINGLETON

Leon Singleton, Houston Oil Field Material Co., is the Gulf Coast Section's new JOURNAL Secretary. He has been closely associated with the industry, particularly in oil field equipment and services since his discharge from the U. S. Army.

Thin Oil Column Reservoirs

Reported By

J. W. Walker

Gulf Coast Study Group

Problems of producing reservoirs with thin oil columns were discussed by R. W. Holman of The Texas Co., following a brief introduction to the subject by Norman Clark of the Humble Oil and Refining Co., before a meeting last month of the Gulf Coast Section Study Group. Clark showed that the thin-oil column reservoir is a special case of the combination drive reservoir. Reservoir mechanics and analysis are the same in both cases; however, individual well problems assume more importance in exploiting thin-oil column reservoirs than in the normal combination reservoir.

Individual well problems were outlined by Holman who presented a detailed discussion of the theory of coning of oil and gas. The effect of sand penetration, completion methods, density differences, and rate of production were discussed. Methods of reducing gas/oil ratios by mechanical means were reviewed. The economical aspects of exploiting thin oil columns encouraged considerable group discussion.

The problems involved in obtaining accurate PVT data were discussed by J. W. Walker of Shell Oil Co. Discussion revealed that in some cases the gas cap of a thin-oil column reservoir has been produced for some time before the presence of a thin oil column is detected. Methods of obtaining representative analyses both of the reservoir liquids and of the gas-cap gas were reveiwed. ★ ★ ★

University of Tulsa Student Activities

By Jack Combes

University Student Chapter

The Student Chapter of the AIME at the University of Tulsa has been very active this past semester. In addition to the sponsorship of lectures by prominent men of the industry, a number of field trips were held to plants in and around Tulsa. A freshman orientation program was also held in November to acquaint the entering petroleum engineering majors with the aims and activities of the AIME.

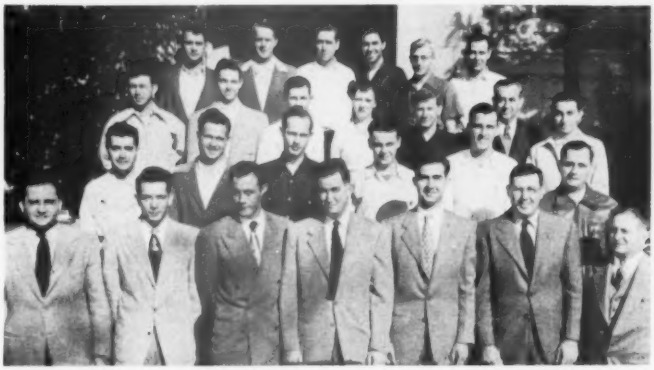
On November 14, Warren B. Davis of Gulf Oil Co. spoke to the chapter on the Dornick Hills-Springer Sand Reservoir, Velma Pool, Okla. He supplemented his talk with slides and the talk was well received by a large group of students.

The following week Lloyd Elkins, director of production research for Stanolind Oil and Gas Co. gave an instructive lecture on "Research: Past, Present and Future." In this talk, Elkins defined research first, then went on to a discussion of the development of research methods.

Following the membership drive in September and October, in which 50 new memberships were received, a number of field trips were taken to various places of interest. These trips included tours of the National Tank Co., Mid-Continent Refinery, Bethlehem Supply Co., and an all-day tour through Southern Oklahoma oil operations in the Golden Trend Area. These trips were all under the sponsorship of Professor A. W. Walker, faculty advisor.

Near the close of the semester, a joint dinner meeting of the Mid-Continent Section and the University of Tulsa was held in the new Student Activities building on the campus. Speaker of the evening was Thomas West of Blanco Oil Co., San Antonio, Tex., who spoke on "A Gravel Pack Completion for Exclusion of Gas and Water."

New officers elected for the 1950-51 school year were Jack Combes, president; Jerry Stafford, vice-president; Tom Carlson, secretary; and Dale Robinson, treasurer. ★ ★ ★



UNIVERSITY OF TULSA STUDENT CHAPTER — 1951 officers and faculty advisers of the Student Chapter at the University of Tulsa are, front row, L to R, E. E. Barberii, instructor; Thomas Carlson, secretary; Jerry Stafford, vice-president; Warren Davis, Gulf Oil Corp., speaker; Dale Robinson, treasurer; Jack Combes, president; and A. W. Walker, faculty advisor.

Meetings of Interest

Spring Meeting of the Interstate Oil Compact Commission will be held in the La Fonda Hotel, Santa Fe, N. M., April 26-28.

It will be impossible to place all those who plan to attend the meeting in the headquarters hotel, but the Commission's headquarters office, Box 3127, State Capitol, Oklahoma City 5, Okla., through which all reservations are being handled, has arranged for accommodations elsewhere. Committee meetings will be held in the headquarters hotel during the Santa Fe meeting; however, general sessions will be held in the Capitol Auditorium on the Capitol grounds.

Bottom-Hole Pressure Build-Up

Southwest Texas Section
Report

William Hurst, petroleum consultant, Houston, Tex., presented to the Southwest Texas Section a talk titled "Significance of Bottom-Hole Pressure Build-up with Respect to Well Completion" before the February meeting of the section in Corpus Christi, Tex.

The speaker dealt with the subject pertaining to the physical concepts associated with bottom-hole pressure build-up. In this respect the effects of well unloading and loading in its relationship to pressure draw-down and build-up were discussed. This likewise included the interpretation of productivity index with respect to well completion, and its significance as established from bottom-hole pressure analysis. The talk was heightened by an interesting discussion which followed, bearing upon the observations of factual field examples. ★ ★ ★

The 1951 officers of the Petroleum Engineers Club (AIME Student Chapter) at the University of Oklahoma are:

E. J. Dickinson, president; Howard M. Perdue, vice-president; S. D. Carnahan, secretary; F. A. Harris, treasurer; A. J. Hankinson, chairman of entertainment; W. T. Massey, manager of publicity; Glen and Omar Emerick, co-chairmen of the open house comittee; and P. G. Von Tungeln, St. Pat's Council representative.

1951 Petroleum Branch Chairman Richard W. French, left, beams broadly at John E. Sherborne, 1950 Chairman, just before the latter relinquished the chairmanship at the Petroleum Branch Banquet in St. Louis. Chairman French had at the time already conducted sessions of the Branch Executive Committee, but the formal changeover did not take place until the night of the banquet.

171st Annual Meeting Held in St. Louis, Mo.

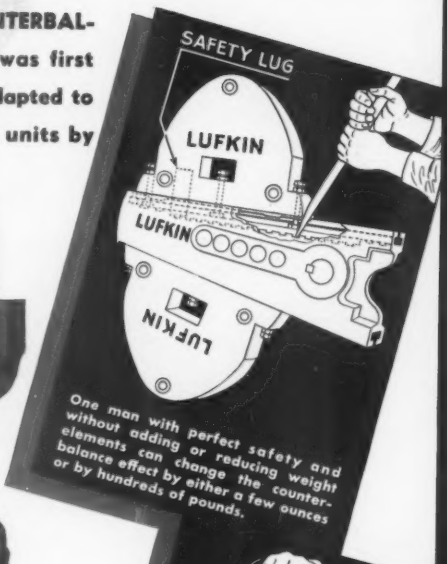
A portion of a technical session audience listen intently to the presentation of one of the 10 papers presented at the four-day meeting. John C. Calhoun of Pennsylvania State College, center middleground, thumbs through his preprint during the delivery.

Lloyd Elkins of Stanolind Oil and Gas Co., Tulsa, Okla., right, has something light to say at the Petroleum Branch banquet. Some 150 members and guests turned out for the informal affair held in the Statler Hotel. Texas Railroad Commissioner William J. Murray was the speaker for the evening.

THE 171st General Meeting of the AIME, held last month in St. Louis, Mo., has been ranked with the most successful staged by the Institute. The practice, established in recent years, of holding the Annual Meeting on alternate years outside New York City has again been proved a wise move. All Branches and Divisions occupied session rooms in four hotels in the Mid-west city. The Statler Hotel, with but four elevators, shuttled Metals and Petroleum people to and from the 16th and 17th floors, respectively, without excessive delay. Meetings were also conducted in the Jefferson, Lennox and DeSoto hotels. The local Lions Club interrupted one of the Petroleum Branch sessions to claim the room for their weekly luncheon site. Most sessions were held before overflow attendance. At right is a view of the registration desk in the Statler lobby.

LUFKIN LEADS!

The TROUT COUNTERBALANCED CRANK was first introduced and adapted to oil field pumping units by LUFKIN in 1923.



One man with perfect safety and without adding or reducing weight elements can change the counterbalance effect by either a few ounces or by hundreds of pounds.

This crank, along with many other patented improvements, have contributed to LUFKIN'S imminent leadership in the industry.

On the smaller Lufkin Units, no tools, other than the wrench furnished with the unit, are necessary to enable one man to change counterbalance as desired.

LUFKIN FOUNDRY & MACHINE COMPANY
LUFKIN, TEXAS

Branch sales and service Houston, Dallas, New York, Tulsa, Los Angeles, Seminole, Oklahoma City, Corpus Christi, Odessa, Kilgore, Wichita Falls, Casper, Wyoming, Great Bend, Kansas.

Lufkin Equipment in CANADA is handled by
THE LUFKIN MACHINE CO., LTD. 14321 108th Avenue, Edmonton, Alberta, Canada

LUFKIN PUMPING UNITS

LUFKIN-COOPER-SUPERIOR ENGINES

LUFKIN OIL FIELD AND INDUSTRIAL TRUCK TRAILERS

INDUSTRIAL SPEED REDUCERS AND INCREASERS

DIVISION LUFKIN FOUNDRY & MACHINE COMPANY INDUSTRIAL, MILL AND AUTOMOTIVE SUPPLIES

DISCUSSION OF THIS AND ALL FOLLOWING TECHNICAL PAPERS IS INVITED
Discussion in writing (3 copies) may be sent to the Editor, *Journal of Petroleum Technology*, 601 Continental Building, Dallas 1, Texas, and will be considered for publication in the Transactions volume *Petroleum Development and Technology*. Discussion will close December 1, 1951. Any discussion offered thereafter should be in the form of a new paper.

CAPILLARY PRESSURE INVESTIGATIONS

HARRY W. BROWN, HUMBLE OIL AND REFINING CO., HOUSTON, TEX., JUNIOR MEMBER AIME

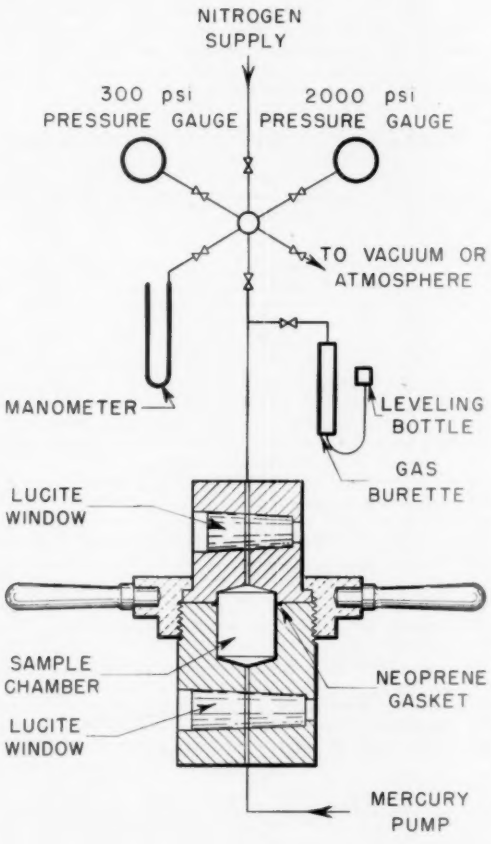


FIG. 1 — CAPILLARY PRESSURE APPARATUS, MERCURY-INJECTION METHOD.

ABSTRACT

This paper presents results of static capillary pressure measurements made both by the restored-state and by the mercury-injection methods, and of dynamic capillary pressure measurements made by the Hassler technique.

The results indicate a variation from sample to sample of the factor used to convert capillary pressure obtained by mercury injection to those applicable to a water-gas system. Static capillary pressures measured by the restored-state method were found to be in close agreement with dynamic capillary pressures, indicating that data obtained from static measurements may be utilized with confidence in the solution of dynamic problems of fluid flow.

Experimental data are presented on the use of "*J*-curves" for the correlation of capillary pressure-saturation relations for a number of cores from a particular geologic formation. It is shown that the correlation was improved in some cases by restricting it to certain lithologic classifications.

INTRODUCTION

The Meaning and Importance of Capillary Pressure

The coexistence of two or more immiscible fluids within the voids of a porous medium, such as reservoir rock, gives rise to capillary forces. Because of the interfacial tension existing at the boundary between two immiscible fluids in a pore space, the interface is curved, and there is a pressure difference across the interface. This pressure difference is termed the capillary pressure.

The magnitude of the capillary pressure between two immiscible fluids which together fill a porous medium depends upon several factors: the textural properties of the medium, the wettability of the medium, the interfacial tension between the fluids, the respective saturations of the fluids, and the manner in which these saturations are attained. For a given pair of immiscible fluids in a particular sample of reservoir rock, the capillary pressure is a unique function of the fluid saturation, provided that the saturation of the fluid which wets the rock has previously been decreased unidirectionally from an initially complete saturation. Similarly, for a given pair of fluids at a particular saturation which has been achieved by a

[1]References given at end of paper.
Manuscript received in the office of the Petroleum Branch Aug. 25, 1950. Paper presented at the Petroleum Branch Fall Meeting in New Orleans, La., Oct. 4-6, 1950.

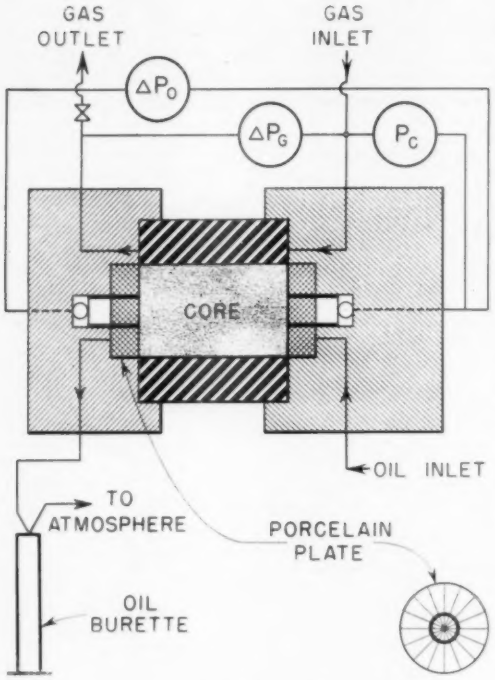


FIG. 2 — DYNAMIC CAPILLARY PRESSURE APPARATUS (HASSLER'S PRINCIPLE).

previous decrease of saturation of the wetting fluid, the capillary pressure depends upon the textural properties and wettability of the reservoir rock.

Although the absolute magnitude of the capillary pressures in most petroleum reservoirs is usually not large, the effects of these capillary pressures are extremely important. Together with gravity they control the original distribution of the fluid saturations within the reservoir, particularly the distribution of connate water. By virtue of their effect on the shapes of the fluid interfaces within the pore spaces, they control in large measure the relative freedom of movement of fluids present in the reservoir, and are important factors in influencing the behavior and distribution of fluids in the production processes.

Previous Investigations on Capillary Pressure

Methods of measuring capillary pressures of fluids in small core samples, and of determining the relation between these capillary pressures and fluid saturations have been given by Leverett[1] and by Bruce and Welge.[2] These authors have proposed the use of the "restored-state" technique, in which the core sample, saturated with a wetting fluid, is placed on a porous diaphragm permeable to the wetting phase. By the application of a known pressure to the non-wetting phase which is confined above the diaphragm, a portion of the wetting phase is expelled from the core sample. By the use of successively higher pressure increments in this procedure a relation between the capillary pressure and fluid saturations may be obtained.

Another technique for determination of capillary pressure has been proposed by Purcell.[3] In this technique, mercury, the non-wetting phase, is injected under pressure into an evacuated core sample. The mercury vapor, together with any residual gas present, corresponds to the wetting phase. The mercury-injection method has the advantage of rapidity of operation, since equilibrium is attained in a short time after the application of each pressure increment. In contrast, equilibrium at each step is attained in the restored-state technique only after a matter of days.

Both the restored-state and mercury-injection techniques are static methods. Dynamic capillary pressures may be determined by a modification of the technique developed by Hassler[4] for measuring relative permeability. In this method both phases are permitted to flow through the core sample, with control being exerted over the pressure difference existing between them. At equilibrium the two phases continue to flow, but their respective saturations do not change.

Leverett[1,5] and Rose and Bruce[6] have pointed out the heterogeneity of reservoir rock and the dependence of capillary pressure on textural properties of the rock. These authors have also proposed a method of correlating the relationship of capillary pressure to saturation with textural properties of rock, in order to extend the applicability of capillary pressure measurements. This method of correlation involves the use of the "*J*-curve," which is discussed in later sections.

PROBLEMS INVESTIGATED IN THIS WORK

Of the numerous problems existing in the measurement and application of capillary pressures, three were investigated during the course of this work.

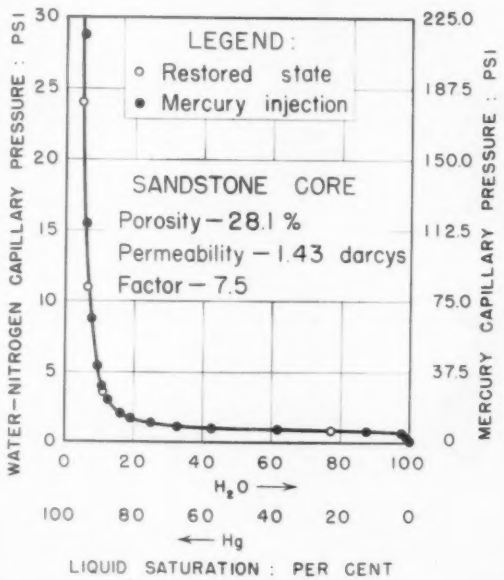


FIG. 3 — CAPILLARY PRESSURES BY RESTORED-STATE AND MERCURY-INJECTION METHODS.

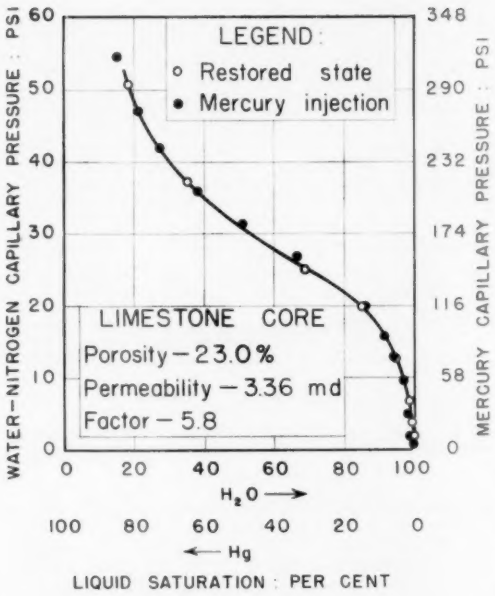


FIG. 4 — CAPILLARY PRESSURES BY RESTORED-STATE AND MERCURY-INJECTION METHODS.

Correlation of Results of Restored-State and Mercury-Injection Methods

Although the restored-state technique is probably the most commonly used method and is generally considered to be the most reliable, the mercury-injection technique has the practical advantage of being much more rapid. Since fluids similar to those encountered in the reservoirs may be used in the restored-state determination, the results are usually more directly applicable to reservoir problems; the results of the mercury-injection method, on the other hand, must be converted by means of a conversion factor to yield those capillary pressures which would be obtained with reservoir fluids. To convert capillary pressures obtained by the mercury-injection method to those obtained by the restored-state technique using water and gas, Purcell[2] has suggested a constant conversion factor which is independent of the character of the reservoir rock.

In view of the complicated character of the material comprising most reservoir rock, and in view of the limited amount of work which has been reported on capillary pressure measurements by the mercury-injection technique, it was deemed advisable to investigate the two methods on a comparative basis. In particular, it was thought pertinent to examine the constancy of the conversion factor for cores from various types of formations.

Comparison of Static and Dynamic Capillary Pressures

Most of the determinations of capillary pressure-saturation relations have been made under static conditions. Although it has been presumed that capillary pressures have an important effect on oil recovery by causing fluid movements to take place when a reservoir is flushed by gas or water, it has not been known whether, when the fluids are in motion, the capillary pressures are the same as when the fluids are at rest. Several papers[3,6,7,8] presented in recent years have proposed methods of applying static capillary pressure data to the solution of dynamic problems of flow. Because of the fundamental nature of the differences between the static and dynamic systems, the validity of such application is subject to some question.

In investigating the various problems connected with capillary pressure determinations, it was particularly desired to compare capillary pressures measured under conditions of static equilibrium with those measured under conditions of dynamic equilibrium during flow.

Correlation of Capillary Properties of Rock with Rock Texture

The method of correlating capillary pressure-saturation relations with permeability, porosity, and wettability of the rock which has been proposed by Leverett[1,5] and by Rose and Bruce[6] requires the use of a dimensionless "capillary pressure-function" group. A plot of this dimensionless group against wetting phase saturation gives the curve generally known as the capillary pressure-function curve or "*J*-curve." It has been suggested that this curve is unique for core samples from a particular geologic formation. If this be true, it is apparent that the *J*-curve, once derived for a particular formation, is of signal importance either in permitting the computation of capillary pressure-saturation relations from known values of permeability and porosity, or in permitting the calculation of the permeability from known values of capillary pressure and porosity. Adequate information on the subject has been lacking, however, and the need for additional data prompted an attempt to confirm the correlation.

EXPERIMENTAL PROCEDURE

Static Capillary Pressure Measurements

Static capillary pressure-liquid saturation relations for core samples were obtained by use of both the restored-state technique and the mercury-injection method. The core samples

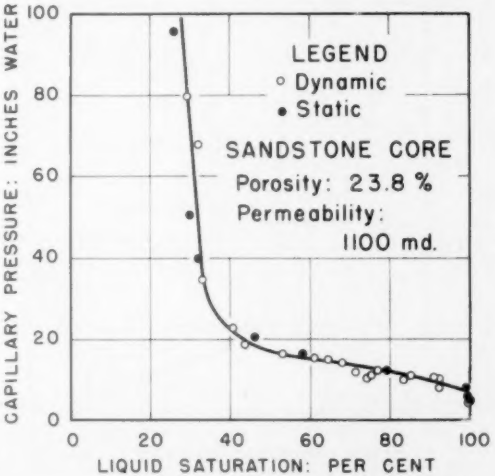


FIG. 5 — CAPILLARY PRESSURES BY STATIC AND DYNAMIC METHODS.

used in these measurements consisted of both limestone and sandstone samples from producing zones.

Restored-State Technique

The displacement cell employed in measurements made by the restored-state technique was of the conventional type, the essential feature of which is the porous porcelain diaphragm. This diaphragm is so chosen that when it is saturated with the fluid to be displaced from the core, it is permeable only to that fluid. When capillary contact is established between the diaphragm and the saturated core, the application of a suitably chosen constant pressure differential across the diaphragm will cause fluid to be displaced from the core, through the diaphragm, to the extent that sufficient fluid remains to satisfy capillary forces. The pressure differential applied across the porous diaphragm is the capillary pressure, because, by definition, capillary pressure is the difference between the pressures of the wetting and non-wetting phases. The quantity of fluid remaining in the core is determined by weighing.

All of the restored-state results presented in this paper were obtained under conditions of decreasing wetting phase saturation.

Mercury-Injection Method

The apparatus used to determine capillary pressure curves by the mercury-injection method was patterned after that described by Purcell[3] and is shown in Fig. 1. The essential components of the apparatus were a mercury displacement pump, a gas burette, a sample holder (shown in detail), and a manifold system wherein the gas pressure could be varied from a high vacuum to the pressure in a commercial nitrogen cylinder.

The gas burette was an addition to the original apparatus, and was added so that the porosity, as well as the capillary pressure curve, could be determined with the same apparatus. Prior to this modification only one of the two quantities needed to determine porosity could be measured with the mercury apparatus, *i.e.*, bulk volume. This made it necessary to determine the solid volume in a separate apparatus. The addition of the gas burette, connected to the chamber of the mercury apparatus, made it possible to determine the solid volume of the sample by the conventional gas-expansion technique. A steel blank of known volume was used to calibrate the system, thus simplifying the calculation of the solid volume of the core sample. This change obviously increases the utility of the apparatus, and should make possible the design of a more compact and portable unit for field use.

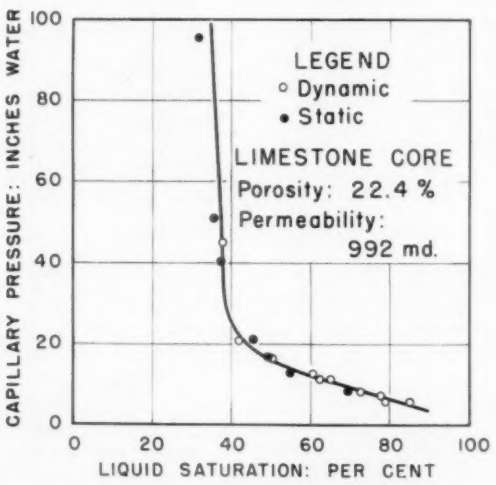


FIG. 6 — CAPILLARY PRESSURES BY STATIC AND DYNAMIC METHODS.

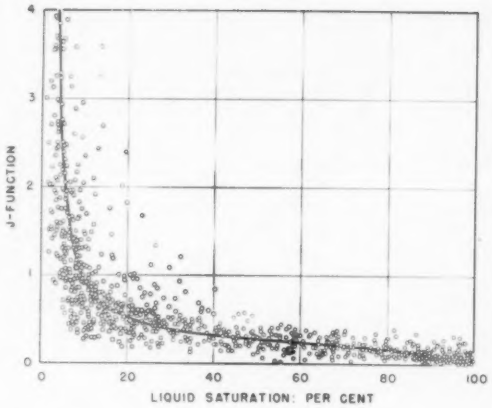


FIG. 7 — J-CURVE FOR ALL CORES, EDWARDS FORMATION, JOURDANTON FIELD.

In operation, the core sample was enclosed in the pressure-tight chamber, the system was pressurized to a predetermined pressure, and the solid volume of the sample was determined by the conventional gas-expansion technique. Next, the system was evacuated, and the volume between two reference marks on the Lucite windows above and below the chamber was determined by introducing mercury into the system with a mercury pump. This volume was subtracted from the known volume of the sample chamber to obtain the bulk volume of the sample. The vacuum pump was then isolated from the system and gas was admitted in increments, thereby increasing the pressure on the mercury surrounding the sample. The penetration of mercury into the pores of the core was indicated by a recession of the mercury-gas interface from the reference mark on the upper Lucite window, and the amount of penetration was determined by advancing the piston of the mercury pump until the mercury meniscus was again at the reference mark. The procedure of alternately building up the pressure and advancing the pump piston was continued until the desired maximum pressure was reached.

DYNAMIC CAPILLARY PRESSURE MEASUREMENTS

During the course of research in fluid mechanics conducted to determine relative permeabilities of reservoir rock to oil and gas, an apparatus designed in principle after that developed by Hassler[4] was constructed which makes it possible to fix directly the capillary pressure between gas and oil, and to maintain that pressure at a fixed and known level while the fluids are flowing.

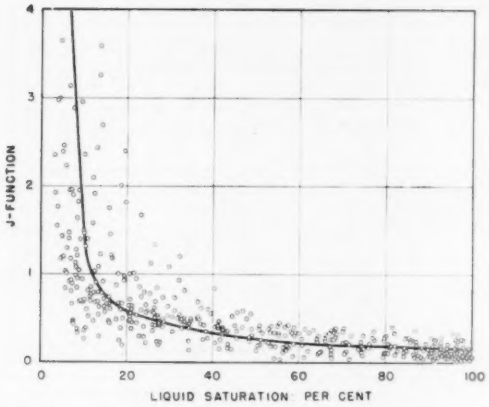


FIG. 8 — J-CURVE FOR LIMESTONE CORES, EDWARDS FORMATION, JOURDANTON FIELD.

The essential features of the Hassler-type apparatus, used to measure dynamic capillary pressures, are shown in Fig. 2. Each of the two end plates consists of a central disc diaphragm and an outer ring diaphragm. The two diaphragms, of porous porcelain, are isolated from each other by means of a metal cylinder. The face of each end plate is grooved to facilitate the passage of gas. The oil is flowed through the outer rings, and the center discs are utilized for measuring the pressure in the oil phase.

In operation, gas and oil were admitted to the core at two different pressures, this pressure difference being the capillary pressure. Since it was possible to measure the pressure drop in the oil phase from one core face to the other by the use of the center section of the porous plate, the gas pressure drop was adjusted at the outlet end until its pressure drop just equaled the pressure drop in the oil phase. When this condition had been attained, equal capillary pressures existed at each end of the core and the saturation was essentially the same throughout the core, if the sample was homogeneous. Any saturation variations due to expansion of the gas were very small because of the low pressure differences employed. While approaching this state of equilibrium, the pressure drop in the gas phase was maintained at a higher value than that in the oil phase. In consequence, prior to equilibrium the saturation at the inlet end was lower than that at the outlet end because of the decreasing capillary pressure gradient in the direction of flow. The liquid in each portion of the core was, therefore, being displaced to a region of higher saturation. The capillary pressure data obtained under these conditions should correspond, as nearly as is physically possible, to the drainage curve arrived at by static methods.

After attaining equilibrium in the manner described above, the core sample was removed and the saturation was determined by weighing.

Determination of Lithologic Properties of Core Samples

A petrographic study was conducted to determine the lithologic character of the core samples which were used in correlating capillary pressure curves. These samples were all from the Edwards formation (Cretaceous Age) of the Jourdanton Field in southwest Texas.

These samples were all carbonate rock, but some were classified as limestone and the others as dolomite or dolomitic limestone.

These samples were predominantly of the intercrystalline porosity type, though some samples had solution-enlarged pores as well.

The samples were divided by visual methods into the following textural groups, classified according to grain size:

1. Microgranular — characterized by not being visibly crystalline in reflected light under 20-power magnification, but individual grains being barely discernible in thin section with 50-power magnification.

2. Fine-grained — visibly crystalline under 20-power magnification, but individual grains not recognizable. Average grain size about 0.02 mm.

3. Coarse-grained — individual grains easily recognizable under 20-power magnification. Dimensions of individual grains exceed 0.04 mm.

RESULTS

Comparison of the Restored-State and Mercury-Injection Methods

Capillary pressure-liquid saturation curves obtained by both the displacement cell and the mercury-injection apparatus were found to be nearly identical when plotted with appropriate scale relationships between the water-gas capillary pressure and the mercury capillary pressure. This identity of results indicates that the capillary pressure-saturation curves obtained by the two methods are geometrically similar, one curve being obtainable from the other for any given core by multiplication of the capillary pressure by a constant. In Figs. 3 and 4 are presented capillary pressure curves obtained by the two methods of capillary pressure measurement for sandstone and limestone cores, respectively.

The results of these studies confirm in general the results published by Purcell,[2] with the exception that Purcell's use of a constant conversion factor for all cores is questionable in the light of the data shown in Figs. 3 and 4. The constant

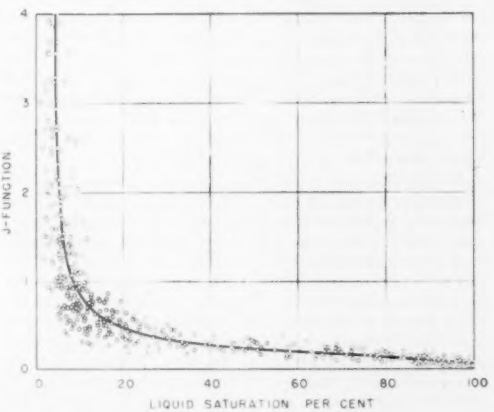


FIG. 9 — J-CURVE FOR DOLOMITE CORES, EDWARDS FORMATION, JOURDANTON FIELD.

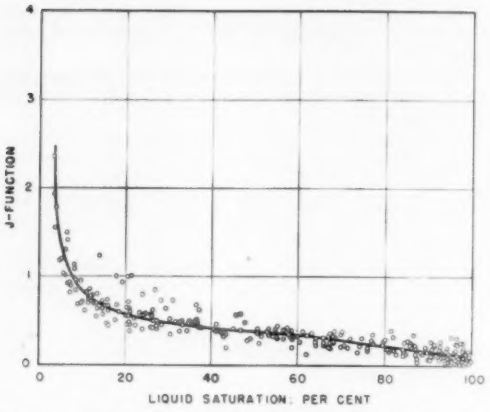


FIG. 10 — J-CURVE FOR MICROGRANULAR LIMESTONE CORES, EDWARDS FORMATION, JOURDANTON FIELD.

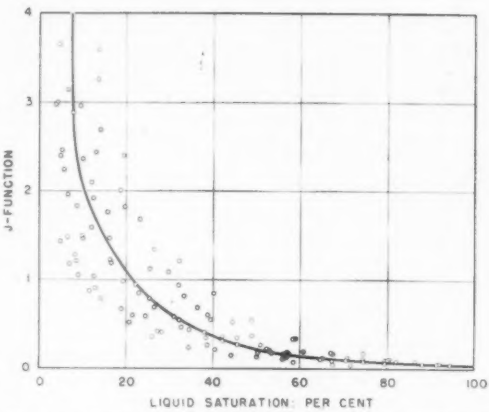


FIG. 11 — J-CURVE FOR COARSE-GRAINED LIMESTONE CORES, EDWARDS FORMATION, JOURDANTON FIELD.

conversion factor used by Purcell was arrived at by assuming the following values:

Surface tension of water: 70 dynes per cm

Surface tension of mercury: 480 dynes per cm

Contact angle of water against the solid: 0°

Contact angle of mercury against the solid: 140°

The conversion factor is then,

$$\frac{\text{(Mercury Capillary Pressure)}}{\text{(Water-Air Capillary Pressure)}} = \frac{-(480)\ (\cos 140^\circ)}{(70)\ (\cos 0^\circ)} = 5.25$$

Purcell, in presenting his results, used as a first approximation for the conversion factor a value of 5.0, and found fair agreement between the results of the two methods.

In contrast, it was found in this study that the agreement could be made almost exact if a different factor, ranging from 5.4 to 8.3, were used for each core sample. The fact that the lowest factor encountered experimentally was 5.4 suggests that the theoretical value of 5.25 may be a limiting value. This supposition is substantiated by the known sensitivity of water surface tension to contamination, making it quite possible that the figure of 70 dynes per cm is a maximum. Therefore, the use of a higher constant factor than that used by Purcell seems justified, and is supported by experimental experience. Data obtained to date indicate that the value of such a factor should be set tentatively as 6.4 for limestone and 7.2 for sandstone. It is expected that future experience will dictate revisions, but for the present these proposed values will, in general, give better correlations.

As stated, it was found that agreement between the two methods for measuring static capillary pressure could be made almost exact, provided the appropriate conversion factors were employed. The determination of one capillary pressure point by the restored-state technique permits the calculation of this factor for a core, if the point is properly located. Fig. 3 may be used to exemplify what is meant by proper location of the point. It may be observed in this figure that the wetting phase saturation is most sensitive to changes in capillary pressure along the horizontal portion of the curve. It is here that the correlating factor must cause the two curves practically to coincide, if large errors in saturation are to be avoided. The known point, therefore, must be in this region. The determination by this procedure of the correct correlating factor makes it possible to obtain a complete curve in detail by the rapid mercury-injection method, and then to convert the mercury curve to a restored-state curve.

Comparison of Dynamic and Static Capillary Pressure Measurements

Comparisons are presented in Figs. 5 and 6 between static and dynamic capillary pressure data for a sandstone and a limestone sample. The two methods show almost exact agreement for each core, and confirm the validity of the assumption that static capillary pressure data apply to flowing systems as well as to static systems, and hence can be utilized in the solutions of dynamic problems of fluid flow. It must be remembered, however, that in each of the two methods only two phases, oil and gas, were present. Neither the two-phase system of oil and water nor the three-phase system of water-oil-gas was investigated.

Correlation of Capillary Properties of Rock with Rock Texture

Leverett's[1,5] capillary pressure function relationship, proposed by Rose and Bruce[6] for correlating capillary pressure curves for samples from the same formation, is

$$J(S_w) = (P_c/\gamma \cos\theta)\,(K/\phi)^{0.5}$$

where

P_c = capillary pressure
K = permeability
ϕ = porosity
γ = interfacial tension between the two fluids, and
θ = the contact angle between the interface separating the two fluids and the surface of the rock.

The group $(P_c/\gamma \cos\theta)\,(K/\phi)^{0.5}$ is dimensionless, and, as shown, is designated as $J(S_w)$, the S_w referring to the saturation of the wetting fluid. A plot of $J(S_w)$ versus wetting phase saturation results in the capillary-pressure-function curve. This curve is more familiarly known as the *J*-curve.

The *J*-curve was employed to correlate capillary pressure liquid saturation data obtained from core samples of the Edwards formation in the Jourdanton Field. The capillary pressure-liquid saturation data were obtained by the restored-state method on cores from various depths in seven wells of this

field. The porosities of these cores varied from 9.5 to 28.2 per cent, and the permeabilities varied from 0.346 to 186 md.

On plotting the capillary-pressure function, $J(S_w)$, against wetting phase saturation it was found that all the data points fell roughly along the same trend. The result, presented in Fig. 7, gives support to the proposal of Rose and Bruce.[6] It was felt, however, that some refinement of the curve would be desirable.

Subsequent studies of the data showed that the curve might be better for cores in the same lithologic classification. Consequently, the cores were divided into groups and plotted as separate *J*-curves according to whether they were limestone, Fig. 8, or dolomite, Fig. 9.

The only improvement noted by this division was for the dolomite samples. As shown by a comparison of Fig. 9 with Fig. 7, the scattering of points was reduced materially, giving much less spread of the data points.

To investigate quantitatively this improvement, the permeabilities of 40 dolomite samples were calculated using the *J*-curve for all cores, Fig. 7, and the *J*-curve for dolomites only, Fig. 9. These calculated permeabilities are compared with the measured permeabilities in Table I. The per cent error, or deviation from the measured value, was determined for each core. The average error for all samples was found to be 71.5 per cent when using the *J*-curve for all cores, Fig. 7. The use of the dolomite *J*-curve, Fig. 9, reduced the average deviation to 48.0 per cent. The variations in porosity and permeability for this group of cores covered such a wide range, threefold for porosity and 500-fold for permeability, that these average per cent errors should be fairly representative for any similar

Table I — Comparison Between Measured and Calculated Permeabilities for Dolomite Cores Using *J*-Curves Indicated

	Core Sample No.	Porosity (fraction)	Measured Permeability K_m (md.)	*J*-Curve for All Edwards Samples		*J*-Curve for Dolomite Only	
				Calculated Permeability K_c (md.)	Deviation %	Calculated Permeability K_c (md.)	Deviation %
Well No. 1	58	.279	186.0	205.0	10.2	144.0	22.6
	65	.225	70.3	155.0	121.0	108.0	53.6
	66	.254	137.0	189.0	38.0	141.0	2.9
	69	.246	154.0	324.0	110.3	274.0	77.9
Well No. 2	1	.117	1.03	1.78	72.8	1.26	22.3
	4	.104	0.346	2.42	599.0	1.68	386.0
	5	.206	20.6	27.4	33.0	20.8	1.0
	6	.159	2.51	4.14	65.0	3.30	31.4
	7	.143	1.97	4.46	126.4	3.19	61.9
	8	.127	7.17	11.1	54.7	7.92	9.5
	10	.201	34.0	42.0	23.6	30.0	11.8
	11	.237	45.0	72.9	62.0	52.1	15.8
	14	.134	1.99	2.11	6.0	1.50	24.6
	18	.113	4.55	7.56	66.1	5.4	18.7
	30	.125	2.29	5.19	126.7	3.7	61.5
	32	.234	160.0	111.0	30.6	78.9	50.7
	33	.200	113.0	112.0	0.9	79.7	29.4
Well No. 3	10	.214	15.9	10.0	37.1	7.18	54.7
	12	.133	2.85	6.85	140.3	4.82	69.1
	16	.236	30.6	17.4	43.1	13.3	56.5
	18	.171	10.7	25.4	137.0	18.9	76.6
	19	.187	53.5	77.5	44.8	57.4	7.3
Well No. 4	1	.220	8.9	11.9	33.7	8.5	4.5
	3	.154	4.07	3.86	5.2	2.94	27.8
	4	.170	2.79	2.25	19.4	1.61	42.3
	7	.253	14.3	15.7	9.8	10.7	25.2
	16	.202	93.0	116.0	24.7	81.9	11.9
	24	.276	28.5	144.0	405.0	106.0	272.0
Well No. 5	3	.131	2.62	7.79	200.0	5.58	115.0
	4	.117	5.07	3.80	25.0	2.71	46.5
	5	.122	1.26	0.785	37.7	0.561	55.5
	6	.155	6.13	6.09	0.7	4.35	29.0
	7	.204	40.8	27.1	33.6	21.8	46.5
	8	.249	67.5	81.2	20.3	62.1	8.0
	9	.212	34.5	39.7	15.1	34.6	0.3
	11	.237	52.5	50.5	3.8	41.5	21.0
	12	.228	53.0	82.5	12.0	60.6	18.1
	14	.235	43.8	50.0	14.2	38.3	12.4
	17	.250	39.5	31.5	20.2	23.8	39.7
	18	.223	74.0	97.7	32.0	73.9	0.1
			Average Deviation, %		71.5		48.0

$$\% \text{ Deviation} = \left(\frac{K_c - K_m}{K_m} \right) 100$$

group of cores from this formation. In this case, therefore, the breakdown of Edwards core samples into two groups, limestone and dolomite, improved the correlation for the dolomite group.

The limestone samples of Fig. 8, were subdivided into two groups according to their texture. One group was the microgranular type, and the other was coarse-grained. As shown in Figs. 10 and 11, respectively, this breakdown into lithologic groups according to texture appears to improve the correlation for both groups.

The dolomites were divided into fine and fine-to-coarse grained dolomites as one group, and coarse-grained dolomites as the other. The improvement in the individual *J*-curves over the *J*-curve for all dolomites was negligible.

The two remaining groups, fine-grained and fine-to-coarse grained limestone were neglected, since the number of cores available was not judged sufficient.

It is apparent from these data that the *J*-curve may have utility in correlating capillary pressure data obtained on samples from a single formation, but that the results derived from its use may be of limited precision. It is also apparent that the correlation may be improved by restricting it to specific lithologic types of samples.

CONCLUSIONS

1. A comparison of the mercury-injection method with the restored-state method of measuring capillary pressure showed that the two yielded nearly identical results if the proper conversion factor were chosen for each core sample, but that the conversion factor was not constant for all samples. This factor was found to average 6.4 for limestone samples and 7.2 for sandstone samples.

2. Static and dynamic methods of obtaining drainage capillary pressure curves gave nearly identical results. This identity confirms the validity of the use of static capillary pressure data in dynamic problems of fluid flow.

3. Data on a number of samples of Edwards limestone support the use of the *J*-curve in correlating capillary pressure data obtained on core samples from a single formation. The correlation may be improved by restricting its use to specific lithologic types from the same formation.

ACKNOWLEDGMENT

The author wishes to express his appreciation for the assistance and cooperation of the persons who contributed to this paper: J. O. Barry, formerly of the Exploration Department, Humble Oil and Refining Co., for the petrographic studies and J. K. Kerver and W. O. Winsauer in securing much of the laboratory data.

REFERENCES

1. Leverett, M. C.: *Trans.* AIME, (1941) **142**, 152-169.
2. Bruce, W. A., and Welge, H. J.: "Restored-State Method for Determination of Oil in Place and Connate Water," API Division of Production, Amarillo, Tex., May 22-23, 1947.
3. Purcell, W. R.: *Trans.* AIME, (1949) **186**, 39-48.
4. Hassler, G. L.: *Method and Apparatus for Permeability Measurement*, U.S. Patent No. 2,345,935, April 4, 1944.
5. Leverett, M. C., Lewis, W. B., and True, M. E.: *Trans.* AIME, (1942) **146**, 175-193.
6. Rose, W., and Bruce, W. A.: *Trans.* AIME, (1949) **186**, 127-142.
7. Rose, W.: *Trans.* AIME, (1949) **186**, 111-126.
8. Gates, J. I., and Lietz, W. T.: "Relative Permeability of California Cores by the Capillary Pressure Method," API Paper No. 801-26F presented before Spring Meeting of Pacific Coast District, May 11-12, 1950. ★ ★ ★

DISCUSSION

By W. R. Purcell, Shell Oil Co., Houston, Tex., Junior Member, AIME

Of the various interesting experimental results reported in Brown's paper, those concerning the conversion of water/nitrogen capillary pressures appear to warrant additional comment. Brown suggests that his observed conversion factors, ranging from 5.4 to 8.3, are higher than the factor of 5.25, previously proposed by the writer, because of a reduction by contamination of the surface tension of water to a value below the 70 dynes per cm which was used in calculating the factor 5.25. One would suspect, however, that the mercury would be as susceptible to contamination as the water, if not more so, and it seems difficult, therefore, to resolve all of the differences merely on the basis of surface tension lowering alone. It should be pointed out that the factor 5.25 as originally proposed was calculated on the assumption that the pores of a rock sample behave as a group of circular capillary tubes. It would seem reasonable therefore, to conclude that the departure of the observed conversion factors from the idealized theoretical value of 5.25 reflects to a large degree the effect of departure of pore geometry from the hypothetical cylindrical tube. It is my opinion that, in the consideration of capillary pressure phenomena, the effect of pore geometry is equally as great as that of surface and interfacial forces,[1] and it is this effect of pore geometry which has been neglected by Brown, and previously by the writer, in considering conversion factors for changing capillary pressures as determined by one system to equivalent values for another system.

REFERENCES

1. Purcell, W. R.: *Trans.* AIME, (1950) **189**, 369.

DISCUSSION

By W. A. Bruce, Carter Oil Co., Tulsa, Okla., Member AIME

It is of interest to me to note that Brown suggests refinement of the *J*-function technique to the extent of subdivision of porous material from a formation into two or more distinct groups. This seems to be a desirable practice if the rock is divisible into distinctly different classifications such as dolomite or calcite as in Figs. 8 and 9 above. However, petrographic classification is not necessarily the key to the *J*-function, probably because a number of petrographic factors such as grain size and standard deviation are already properly accounted for macroscopically by the permeability and porosity values that go to make up the *J*-function. ★ ★ ★

VARIABLE CHARACTERISTICS OF THE OIL IN THE TENSLEEP SANDSTONE RESERVOIR, ELK BASIN FIELD, WYOMING AND MONTANA

RALPH H. ESPACH, MEMBER AIME, AND JOSEPH FRY, U. S. BUREAU OF MINES, LARAMIE, WYO.

ABSTRACT

In the spring of 1943, when it was evident that the Tensleep sandstone in the Elk Basin Field, Wyoming and Montana, held a large reserve of petroleum, Bureau of Mines engineers obtained samples of oil from the bottom of nine wells and analyzed them for such physical characteristics as the volumes of gas in solution, saturation pressures or bubble points, shrinkage in volume caused by the release of gas from solution, expansion of the oil with decrease in pressure, and other related properties. The composition of the gas in solution in the oil was studied. The pressures and temperatures existing in the reservoir and the productivity characteristics of the oil wells were determined.

The data obtained indicate that the oil in the Tensleep Reservoir of the Elk Basin Field has unusually varying physical characteristics, such as a saturation pressure of 1,250 psia and 490 cu ft of gas in solution in a barrel of oil at the crest of the structure and a saturation pressure of 530 psia and 134 cu ft of gas in solution in a barrel of oil low on the flanks. The hydrogen sulfide content of the gas in solution in the oil varies from 18 per cent for oil on the crest to 5 per cent for oil low on the flanks of the structure. Of even greater significance is the fact that these and other variable characteristics of the reservoir oil are related to the position of the oil in the structure. Many geologists and petroleum engineers have considered that all the oil in a petroleum reservoir has rather uniform physical characteristics and that equilibrium conditions prevailed in all underground accumulations of oil and gas; that such is not always so is borne out by the results of the study by the writers.

INTRODUCTION

The Rocky Mountain region is one in which may be found striking examples of the unusual in oil and gas accumulations, as is evident from the following: The high helium content (7.6 per cent) of the gas in the Ouray-Leadville limestone sequence in the Rattlesnake Field, New Mexico, and gases of similar helium content in other fields; 50° to 55° API gravity distillate in solution in carbon dioxide gas and recoverable through retrograde condensation, in the North McCallum Field, Colorado; the occurrence of gas, oil, or both in closely related structures contrary to the usual concepts of gravimetric segregation; the accumulation of gas and/or oil in structures closely related to other structures that apparently are more favorable but do not contain oil or gas accumulations; the high hydrogen sulfide content (as high as 42 per cent) of the gas associated with oil in some fields in the Big Horn Basin, Wyoming; and the wide range of fluid characteristics found in the Elk Basin reservoir.

Elk Basin, an interesting old oil field that has been producing oil from the Frontier formation since 1915, is situated in a highly eroded basin resulting from the erosion of the crest of an anticline and some of the underlying softer shales. The field came back into national prominence during 1943 when it became known that it was the largest single reserve of new oil discovered in the United States that year. The Tensleep sandstone was found to contain oil in November, 1942, when a well drilled to a depth of 4,538 ft (44 ft into the Tensleep sandstone) flowed oil at the rate of 2,500 B/D. By the end of 1949, 137 oil-producing wells and five dry holes had been drilled, and approximately 32 million bbl of oil had been produced. Approximately 6,000 acres may be considered productive of oil in the Tensleep Reservoir, and estimates of the oil that will be produced average 200 million bbl.

The Tensleep Reservoir has further interest because it has greater closure than any oil field in the Rocky Mountain region; the closure of the Elk Basin anticline is variously estimated at 5,000 to 10,000 ft, of which the top 2,000 ft of the structure contained oil.

SUBSURFACE OIL SAMPLING

Fig. 1 is a structural map of the Elk Basin Tensleep Reservoir, on which the nine wells used in this study and the numbers corresponding to the well designations hereafter referred to are shown. Wells 1, 2, 3, 4, and 8 were tested and sampled during October and November, 1943, and Wells 5, 6, 7, and 9 during June and July, 1944.

An electromagnetic type sampler developed by the Bureau of Mines and described by Grandone and Cook[1] was used in obtaining the subsurface oil samples.

As the wells were tubed nearly to bottom, the sampler was run as far as possible in the tubing but never below the top perforations.

The following procedure was used in testing and sampling the wells: A well was shut in for at least three days, after

[1]References given at end of paper.

Manuscript received in the office of the Petroleum Branch Aug. 31, 1950. Paper presented at the Petroleum Branch Fall Meeting in New Orleans, La., Oct. 4-6, 1950.

which shut-in subsurface pressures and temperatures were measured. Generally, the well then was allowed to flow at a 10 to 20-bbl-per-hour rate for approximately one day, when a flowing temperature and pressure traverse was run. One day later, at the same production rate, a subsurface sample was obtained and transferred to a storage container. A second subsurface sample of oil then was procured; and, if in transferring, the pressure and volume data duplicated those of the first sample, both were considered satisfactory for analyses. After the sampling was completed the flow rate of the well was increased to two higher rates and subsurface pressure traverses were obtained at each rate. A 12-hour subsurface pressure build-up was obtained when the well was shut in following the highest rate of flow. A pressure gauge recorded the tubing and casing pressures at the wellhead during the tests. The oil produced by the well during the tests was gauged in lease tanks at regular intervals and the separator gas was measured with a recording orifice meter. The essential data pertaining to the wells are given in Table 1.

Wells 7 and 9 were not producing when sampled. Well 7 had flowed most of the indicated production; but the flow gradually lessened, and the well finally stopped flowing. It was sampled several days later. Well 9 was swabbed unsuccessfully to cause it to flow; it had been standing for about 30 days before sampling, and as tubing had not been run to bottom, it was necessary to sample the oil at a relatively high point in the well.

It will be noted that Wells 2 and 3 have essentially the same structural position, and for the purposes of this study it might seem that one well would suffice. Well 3, however, produced from the upper 44 ft of the Tensleep formation, and Well 2 was completed so that only the zone between 66 and 192 ft below the top of the Tensleep formation produced oil through the tubing. Sampling both wells provided an excellent opportunity to study the possibility of the existence of more than one reservoir in the Tensleep formation, a postulate that had merit because of the rather extensive dolomitic zones extending throughout the sandstone body at depths greater than 70 to 80 ft in the formation. The almost identical results obtained in the analyses of the oil samples from both wells indicated that the oils were the same and that the Tensleep formation contained only one reservoir.

RESERVOIR-OIL CHARACTERISTICS

The subsurface oil samples were analyzed by the differential gas-liberation method outlined by Grandone and Cook.[1] The laboratory analyses of the oil samples were made at the Petroleum Experiment Station (now Petroleum and Oil-Shale Experiment Station), Bureau of Mines, Laramie, Wyo., during several months following sampling of the wells. The general results are given in Table II. Individual gas-liberation data for the nine samples are not presented, but Figs. 2, 3, and 4 show how the data changes for the oil at wells 1, 6, and 8.

In these figures, the graphs of "expansion of sample" are self-explanatory. The values for the gas in the "gas in solution" graphs are figured at conditions of 60°F and 14.4 psia pressure. The "relative oil-volume" graphs show the volume relationship between the oil in the reservoir under reservoir conditions and the residual oil at 60°F. The "density of sample" graphs indicate the change in density as changes in pressure and release of solution gas occur. The "specific gravity of gas in solution" graphs show the gravity of the gas that is in solution in the oil at the different pressures and in volume as shown by the "gas in solution" graphs. The values for the specific gravity of the gas in solution were obtained by using a 220-ml gas-density balloon, weighing samples of gas liberated between pressure points and calculating the composite to any pressure by using the volumes and weights of the several increments of liberated gas.

The "hydrogen sulfide content of gas in solution" graphs show the percentage of hydrogen sulfide in the gas that is in solution in the oil at the different pressures and in volume as shown by the "gas in solution" graphs. The percentages of H_2S were obtained by running both Tutwiler and Orsat analyses of the increments of liberated gas during analyses of samples from wells 5, 6, 7, and 9 and Orsat analyses for acid gases of the increments of liberated gas during analyses of samples from Wells 1, 2, 3, 4, and 8. Where Orsat values alone were determined, 5 to 6½ per cent was subtracted from them as a correction for the carbon dioxide content of the gas. The "hydrogen sulfide content of gas in solution" graphs represent values obtained from: The determined percentages of hydrogen sulfide in the several increments of gas liberated between any two pressures; the volumes of the several increments; and the calculated composites of these to various pressures.

Of interest in connection with the "gas in solution" graphs are the data on the H_2S contents of the several increments of

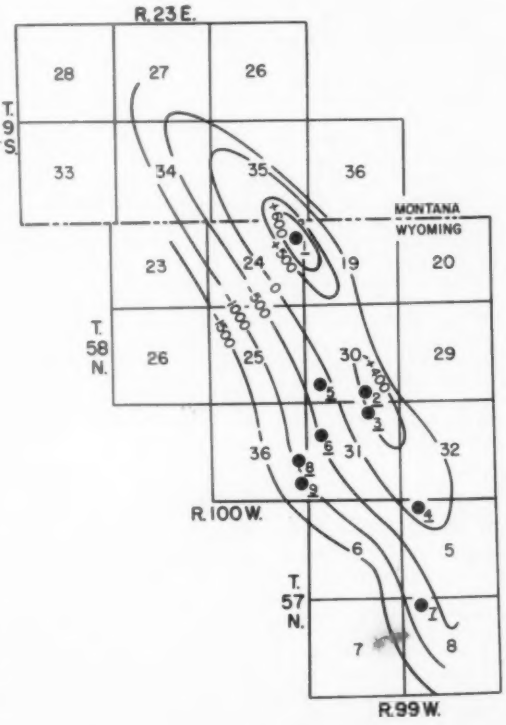


FIG. 1 — ELK BASIN, TENSLEEP RESERVOIR MAP.

Table I — Data Relative to Wells Sampled, Tensleep Reservoir, Elk Basin Field

Well No.	Date of well completion	Date of sampling	Oil produced to sampling date, bbl	Gravity of produced oil, °API	Top of Tensleep formation: Elevation, ft	Top of Tensleep formation: Original pressure, psia[1]	Top of Tensleep formation: Temperature, °F[2]	Sampling point: Elevation, ft	Sampling point: Pressure, psia	Flow rate while sampling B/D
1	9- 9-43	11- 4-43	20,000	31.8	+655	1853	112	+488	1564	922
2	3- 9-43	10-23-43	114,000	31.4	+471	1917	115	+283	1734	454
3	4-18-43	10-15-43	130,000	31.1	+422	1934	116	+413	1644	536
4	7- 6-43	10- 4-43	34,800	31.0	+ 89	2049	121	- 30	1905	420
5	4-28-44	6-11-44	6,200	30.6	-117	2120	125	-265	1570	486
6	5- 2-44	6-21-44	9,200	30.0	-397	2218	129	-557	1720	240
7	4- 4-44	6-15-44	13,800	29.1	-683	2319	134	-773	1882	shut-in
8	8- 7-43	10- 9-43	52,700	28.4	-887	2392	137	-1044	2023	440
9		5-31-44	200[3]	27.1	-1107	2472	141	-643	1770	shut-in

[1]Calculated from estimated original reservoir pressure of 2,080 psia at sea-level datum and density of subsurface samples.
[2]From temperature gradient chart for the Elk Basin structure.
[3]Production by swabbing in an attempt to cause the well to flow. Well was pumped after sampling.

gas liberated during the differential gas liberation of a subsurface sample of oil. Such data from the sample of oil from Well 1 are given in Table III. The great change in H_2S content of the gas as it is released from solution when the pressure is lowered is significant. It reflects the solubility of H_2S in crude oil. The "hydrogen sulfide content of gas in solution" graphs indicate that at Elk Basin the H_2S content of the gas from the oil in the reservoir would increase as reservoir pressures decreased in accordance with the graphs provided the gas/oil ratio during production would not exceed that in solution in the oil. However, gas/oil ratios will increase in solution-gas-drive reservoirs as the pressure declines. The percentage of hydrogen sulfide in the gas evolving from solution also will increase as reservoir pressure declines; this relationship is shown in Table III for an oil sample from Well 1: The relationship is similar for oil samples from other wells. These two factors will cause a decrease in the percentage of hydrogen sulfide in the produced gas as reservoir pressures decline, for the volume of gas produced in excess of the volume of gas in solution in the oil will have a smaller percentage content of hydrogen sulfide and will act as a diluent for the solution gas. Later in the life of the reservoir when declining gas/oil ratios become effective, an increase in the H_2S content of the produced gas can be expected.

Owing to the method by which the data were obtained, those data relating to the specific gravity of the increments of gas liberated from the subsurface oil samples and the hydrogen sulfide content of the gas samples are the least accurate of all results reported. In fact, the data show changes in one or two instances that are inconsistent with the data from other samples.

The writers are indebted to two of the operators for information on the viscosity of the reservoir oil from Well 2. Oil from Well 2 is representative of the oil in the upper 500 or more feet of closure. The viscosity in centipoises of the oil at a temperature of 123°F and at several gauge pressures and the estimated viscosities of the oil near the edge of the reservoir are given in Table IV.

DISCUSSION

A review of the data given in Table II and shown in Figs. 2, 3, and 4, reveals a very interesting conclusion that should be considered in all studies of petroleum reservoirs; namely, that the oil in a reservoir may have rather widely varying physical characteristics.

In general, many engineers and geologists have reasoned that, considering the length of time involved in the formation of an oil field, equilibrium must have been attained between

Table II — General Results of Analyses of Subsurface Oil Samples, Tensleep Reservoir, Elk Basin Field

Well No.	Gravity, °API: At original reservoir pressure	Gravity, °API: Residual oil, after liberation of gas	Gas-liberation temperature, °F	Saturation pressure, psia	Gas in solution cu ft/bbl residual oil[1]	Relative oil volume[2]	Expansibility factor[3]	Specific gravity of gas in solution	Hydrogen sulfide content of gas in solution, per cent
1	45.4	30.7	121	1250	490	1.223	82 x 10^{-5}	0.989	18.2
2	44.9	30.2	121	1255	478	1.220	82 x 10^{-5}	.996	15.8
3	45.4	30.6	121	1250	469	1.221	79 x 10^{-5}	1.001	16.6
4	44.3	30.6	123	1235	459	1.212	77 x 10^{-5}	1.011	16.5
5	44.6	30.2	129	1177	437	1.210	84 x 10^{-5}	1.028	15.2
6	42.3	29.5	133	990	350	1.178	70 x 10^{-5}	1.048	13.4
7	39.2	29.1	134	772	225	1.122	68 x 10^{-5}	1.021	6.4
8	37.3	27.7	140	695	205	1.116	64 x 10^{-5}	1.026	10.1
9	34.9	27.0	141	530	134	1.086	63 x 10^{-5}	1.041	4.9

[1]Based upon differential gas-liberation method. Base, 14.4 psia and 60°F.
[2]Ratio of reservoir-oil volume (at original reservoir conditions at top of Tensleep formation) to residual-oil volume at 60°F.
[3]Volumes per volume per psi pressure change, reservoir oil at pressures above saturation pressure.
[4]This figure probably is in error. Corresponding data from other samples indicate that it should have been approximately 75 x 10^{-5}.

the fluids in a reservoir and if any of the oil was saturated with gas under existing pressures and temperatures, then all of it was saturated or very nearly so, or, conversely, if some of the oil was undersaturated, then all of it would be undersaturated to about the same degree. Some recorded observations in other fields seem to indicate that equilibrium conditions may not exist in all fields, but incontrovertible proof of that has been lacking. Estabrook and Rader[3] noted the presence of a "zone of dead oil" in the Second Wall Creek sand in the Salt Creek Field and reported that "the distribution of dissolved gas in the oil seems to have been fairly uniform over the field except toward the edges."

Study of the magnitude of change of properties of the subsurface oil samples from Elk Basin definitely indicates that the fluids in a reservoir are not necessarily in equilibrium. It is concluded that either extremely long periods of time are necessary to effect equilibrium or that accumulation can be quite young, or is still taking place in some petroleum reservoirs.

Table III — Hydrogen Sulfide Content of Liberated Gas, Differential Gas Liberation, Oil Sample from Well 1

Pressure range in which gas increment liberated, psia	Hydrogen sulfide content of gas increment, per cent
1250 to 835	7.6
835 to 725	5.1
725 to 625	5.9
625 to 535	6.8
535 to 450	6.1
450 to 365	10.2
365 to 300	13.0
300 to 225	16.0
225 to 165	19.4
165 to 120	26.7
120 to 85	28.6
85 to 60	35.0
60 to 45	38.0
45 to 11	36.1

RELATIONSHIP OF OIL CHARACTERISTICS TO RESERVOIR STRUCTURE

The relationship of the characteristics of the oil to the location of the oil in the Elk Basin, Tensleep Reservoir, is shown in Fig. 5. In Fig. 5 values of the saturation pressure, gas in solution, relative oil volume, density of the reservoir oil, specific gravity of the gas in solution, and hydrogen sulfide content of the gas in solution for the nine subsurface oil samples are plotted as ordinates against the common abscissa of sea-level elevations of the top of the Ten-sleep formation over the structure. The nine wells shown in Fig. 1 are identified by number along the abscissa of Fig. 5 at positions corresponding to the elevation of the top of the Tensleep in each well. Although the wells are plotted according to formation "tops" the oil from each of these wells came from some greater depth, depending on the penetration (160 to 200 ft) of the formation in each well.

The composite sample data for the oil from each of the wells sampled, as derived from the individual analyses, are shown in Fig. 5 to have a very definite relationship to the structure of the reservoir from which the oil came. To the writers' knowledge, this is the first time that results of detailed reservoir oil sampling have been published showing such a relationship to exist.

A study of Fig. 5 would indicate that possibly the subsurface sample of oil from Well 7 was not truly representative of the reservoir oil at Well 7 and that the sample had been conditioned somewhat. This was referred to in the section on subsurface oil sampling. The data for the specific gravity of the gas in solution show the least consistent relationship of all the data. Attention has been called earlier in this report to the manner in which these data were acquired.

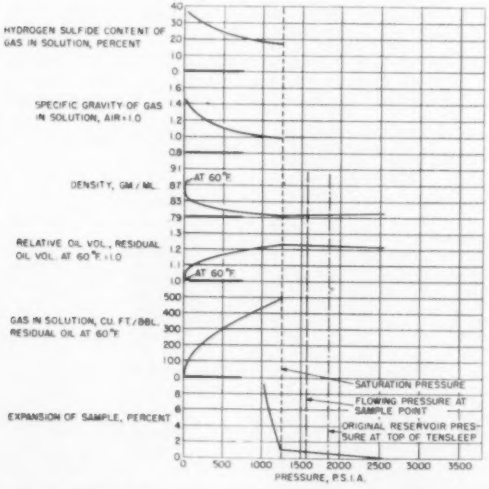

HYDROGEN SULFIDE CONTENT OF GAS IN SOLUTION, PERCENT
SPECIFIC GRAVITY OF GAS IN SOLUTION, AIR=1.0
DENSITY, GM./ML.
AT 60°F.
RELATIVE OIL VOL., RESIDUAL OIL VOL. AT 60°F.=1.0
GAS IN SOLUTION, CU. FT./BBL. RESIDUAL OIL AT 60°F.
EXPANSION OF SAMPLE, PERCENT
SATURATION PRESSURE
FLOWING PRESSURE AT SAMPLE POINT
ORIGINAL RESERVOIR PRESSURE AT TOP OF TENSLEEP
PRESSURE, P.S.I.A.

FIG. 2 — RESULTS OF DIFFERENTIAL GAS-LIBERATION ANALYSIS AT 121°F, SUBSURFACE OIL SAMPLE FROM WELL 1, ELK BASIN FIELD.

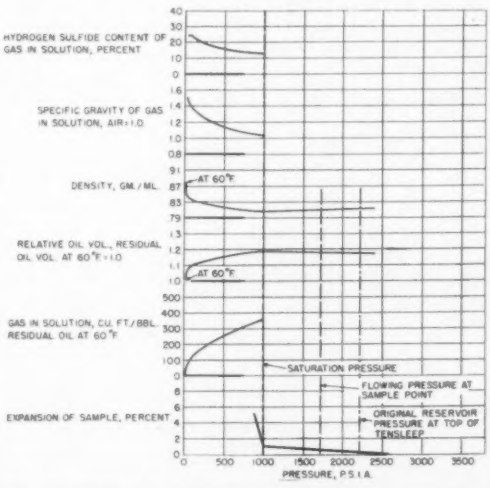

HYDROGEN SULFIDE CONTENT OF GAS IN SOLUTION, PERCENT
SPECIFIC GRAVITY OF GAS IN SOLUTION, AIR=1.0
DENSITY, GM./ML.
AT 60°F.
RELATIVE OIL VOL., RESIDUAL OIL VOL. AT 60°F.=1.0
GAS IN SOLUTION, CU. FT./BBL. RESIDUAL OIL AT 60°F.
EXPANSION OF SAMPLE, PERCENT
SATURATION PRESSURE
FLOWING PRESSURE AT SAMPLE POINT
ORIGINAL RESERVOIR PRESSURE AT TOP OF TENSLEEP
PRESSURE, P.S.I.A.

FIG. 3 — RESULTS OF DIFFERENTIAL GAS-LIBERATION ANALYSIS AT 133°F, SUBSURFACE OIL SAMPLE FROM WELL 6, ELK BASIN FIELD.

Table IV — Viscosity of Reservoir Oil

Pressure, psi	Oil from Well 2, centipoises	Oil from edge wells, centipoises (estimated)
2500	1.59	4.6
2000	1.50	—
1500	1.42	4.3
1150	1.35	—
1000	1.40	—
800	1.50	4.1
600	1.65	4.0
400	1.82	4.1
200	2.05	4.7
0	4.50	8.0

The physical characteristics of the oil throughout the crestal 500 to 600 ft of the reservoir are very much alike — all oil samples from the crestal part of the reservoir showed a saturation pressure of 1,235 to 1,250 psia and contained 460 to 490 cu ft of gas in solution based on 1 bbl of residual oil. As a consequence of this gas in solution, 1.22 bbl of oil in the reservoir are required to produce 1 bbl of residual, or approximately stock-tank, oil. At a depth of about 100 ft above sea level, a decided change begins to occur in the character of the reservoir oil—the saturation pressure becomes lower and the volume of gas in solution decreases. The other characteristics begin to change also. These changes continue with depth until the oil from a well in which the top of the producing formation is at an elevation of 1,107 ft below sea level, contains only 134 cu ft of gas in solution per barrel of oil (on a residual oil basis) and its saturation pressure is only 530 psia. Edge water is present in the reservoir at an elevation of about 1,500 ft below sea level. The writers have no information on the characteristics of the oil coming from wells in which the top of the Tensleep sandstone is below a depth of 1,107 ft below sea level. Characteristics may be inferred from extension of the several curves to elevations of 1,200 or 1,500 ft below sea level.

The hydrogen sulfide content of the gas in solution in the oil as compared to the volume of gas in solution in the different oil samples is a rather interesting relationship; the gas in solution in the oil on top of the structure contains 18 per cent hydrogen sulfide, that in solution in the oil on the edge of the structure contains 5 per cent, and the variation is almost directly proportional to the volume of gas in the different samples. This suggests a plausible hypothesis for the movement and characteristics of the fluids in the reservoir which is consistent with the supposition that equilibrium has not yet been attained in the whole mass of reservoir oil and which has been included in another article[5] concerning the Elk Basin Field.

ACKNOWLEDGMENTS

The work covered in this report was conducted under a cooperative agreement between the Bureau of Mines, United States Department of the Interior, and the University of Wyoming.

The writers and those engaged in the work appreciate the assistance of the operators in the Elk Basin Field, who gave the engineers of the Bureau of Mines access to their properties, supplied the wells for testing and sampling purposes, and furnished most of the information pertaining to the Tensleep reservoir itself.

The report was prepared under the general supervision of R. A. Cattell, Chief, Petroleum and Natural Gas Branch, Bureau of Mines, Washington, D. C., and H. P. Rue, Chief, Fuels Technology Division, Region IV, Petroleum and Oil-Shale Experiment Station, Bureau of Mines, Laramie, Wyo. The constructive criticisms of the manuscript by C. B. Carpenter

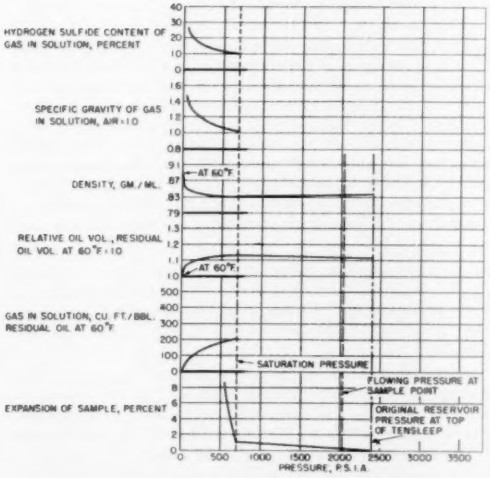

HYDROGEN SULFIDE CONTENT OF GAS IN SOLUTION, PERCENT
SPECIFIC GRAVITY OF GAS IN SOLUTION, AIR=1.0
DENSITY, GM./ML.
AT 60°F.
RELATIVE OIL VOL., RESIDUAL OIL VOL. AT 60°F=1.0
AT 60°F.
GAS IN SOLUTION, CU. FT./BBL. RESIDUAL OIL AT 60°F.
SATURATION PRESSURE
FLOWING PRESSURE AT SAMPLE POINT
ORIGINAL RESERVOIR PRESSURE AT TOP OF TENSLEEP
EXPANSION OF SAMPLE, PERCENT
PRESSURE, P.S.I.A.

FIG. 4 — RESULTS OF DIFFERENTIAL GAS-LIBERATION ANALYSIS AT 140°F, SUBSURFACE OIL SAMPLE FROM WELL 8, ELK BASIN FIELD.

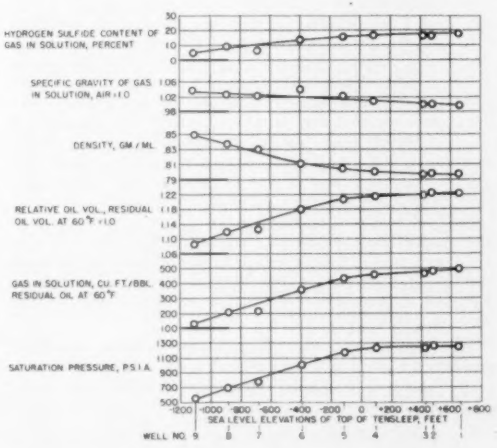

HYDROGEN SULFIDE CONTENT OF GAS IN SOLUTION, PERCENT
SPECIFIC GRAVITY OF GAS IN SOLUTION, AIR=1.0
DENSITY, GM./ML.
RELATIVE OIL VOL., RESIDUAL OIL VOL. AT 60°F=1.0
GAS IN SOLUTION, CU. FT./BBL. RESIDUAL OIL AT 60°F.
SATURATION PRESSURE, P.S.I.A.
SEA LEVEL ELEVATIONS OF TOP OF TENSLEEP, FEET
WELL NO. 9 8 7 6 5 4 3-2 1

FIG. 5 — RELATIONSHIP OF THE CHARACTERISTICS OF THE OIL AT ORIGINAL CONDITIONS TO THE LOCATION OF THE OIL IN THE TENSLEEP RESERVOIR, ELK BASIN FIELD.

(deceased), A. B. Cook, H. C. Miller, and E. M. Tignor, engineers of the Bureau of Mines, are gratefully acknowledged. The work of three engineers, formerly at the Laramie Experiment Station — H. Karl Schmidt and Warren J. Mason on the first group of oil samples and Raymond A. Morgan on the second group of samples — in addition to that of the writers, resulted in acquiring the data presented in this report. O. C. Heustis prepared the illustrations.

REFERENCES

1. Grandone, Peter, and Cook, Alton B.: *Collecting and Examining Subsurface Samples of Petroleum*, U. S. Bureau of Mines Technical Paper 629, (1941), 12-19, 59-64.
2. Estabrook, E. L., and Rader, C. M.: *Trans.* AIME, (1925), 216.
3. Espach, Ralph H., and Fry, J.: U. S. Bureau of Mines Report of Investigations 4768, (1950).

DISCUSSION

By Henry J. Welge, Carter Oil Co., Tulsa, Okla., Member AIME

For some time geologists and engineers have tacitly assumed that the elapsed time during which petroleum reservoirs have been relatively undisturbed is sufficiently large so that their fluids are in complete equilibrium with one another. Hence the authors are to be commended for directing attention to the possibility of the occurrence of non-equilibrium conditions in certain petroleum reservoirs. Work recently performed at The Carter Oil Co. Research Laboratory substantiates this point. In the interest of adding to the picture, a portion of the work done recently is herewith presented.

In order to test the possibility of an incomplete approach toward equilibrium by diffusion of gas downstructure in the Elk Basin Pool, calculations have been made of the minimum time required for the attainment of the present gas distribution at the downstructure wells (6, 7, 8, and 9 on Fig. 1) by diffusion. The calculations presume a constant dissolved gas content of 467 cu ft per bbl at all times at levels higher than the present sea level contour (Fig. 1). They also assume that no, or relatively little, gas was in solution elsewhere in the reservoir at the time of trap formation. In other words, the picture assumed is that of gas (or gas-rich oil) present initially in the upper part of the reservoir, overlying relatively "dead" oil. It is well known that rather long intervals of time are required for a solute to diffuse through a liquid if long distances have to be traversed. The calculations were made in order to see how long a time interval is required in the instance of the Elk Basin Pool, and to compare it with the geologic time available.

The relation governing unsteady state diffusion is mathematically identical with that treating heat diffusion. For conductors of certain shapes, the solutions have been given graphically.[1,2]

The special case of a constant high concentration of gas at the head of a petroleum column, maintained by the presence of a gas cap diffusing downward into the oil, is analogous to heat flow through a slab of uniform cross-sectional area, from a constant temperature source at one face toward an opposite insulated face.

The solution for the slab shape assumes a uniform cross-sectional area normal to the direction of diffusion. This condition would prevail approximately on the elongated southwest and northeast flanks of the pool, as indicated in Fig. 1 of the paper under discussion. With the aid of this graphical solution, it is possible to compute the time required for the present gas distribution to be attained. The value used in this calculation for the diffusion constant, D, is 0.43 sq ft per year, and it compares favorably with values given in the literature.[3] The lengths used for the diffusion paths toward the downstructure wells have been estimated with the aid of the field map, Fig. 1.

The computations are summarized in the table below.

1. Well No.	6	7	8	9
2. Gas-oil ratio, cu ft/bbl = G	350	225	205	134
3. Gas concentration ratio, $Y = (467\text{-}G)/467$	0.25	0.518	0.56	0.713
4. Horizontal distance (Fig. 1) from oil-water contact to well, ft = a	3440	3020	1780	1200
5. Horizontal distance from oil-water contact to sea level contour = b	4970	7040	4970	4970
6. Position ratio $n = a/b$	0.692	0.430	0.359	0.242
7. Angle of dip (Fig. 1), degrees	20	12	20	20
8. Inclined distance from sea level contour to oil-water contact, ft = R	5280	7190	5280	5280
9. R^2, ft^2, x 10^{-6}	27.9	51.9	27.9	27.9
10. X (from Y and n[1,2])	0.33	0.30	0.32	0.22
11. Diffusional time = $X R^2/D$ years x 10^{-6}	21.4	36.2	20.8	14.3

It will be noted from the last line in the table that the times required for diffusion are long, of the order of 15-40 million years, and are not incompatible with the hypothesis that gas diffused downstructure from the crestal region of high gas concentration throughout the geologic time elapsed since trap formation, without reaching complete equilibrium in the time available.

Several other possible explanations for the observed variation in composition of the petroleum in the Elk Basin Field have also been considered. In all cases they can explain only relatively small variations in composition. For example, Sage and Lacey[4] have computed for a similar reservoir the variation expected because of gravitational segregation. They found that, over as much as 2,000 ft of closure, the expected variation for methane was only about 1/20 of the average amount of methane in solution. This explanation obviously would not account for the differences observed at Elk Basin.

Considering, finally, the possibility of segregation due to temperature difference between the top and bottom of the oil column, Sage and Lacey[5] have found that the change in solubility of natural gas expected with a temperature change of from 120°F to 140°F was also about 1/20 of the total gas solubility.

Apparently considerations other than the assumption of incomplete attainment of equilibrium lead to the conclusion that comparatively little variation in petroleum composition should be observed in a reservoir at equilibrium, even though its closure extends over several thousand feet. This conclusion is demonstrated by the existence of a number of oil reservoirs having a large closure, but whose petroleum is of substantially uniform composition. Therefore, when a considerable

variation in composition is encountered, as at Elk Basin, a satisfactory explanation may be incomplete diffusional approach toward equilibrium.

REFERENCES

1. Gurney and Lurie: *Ind. Eng. Chem.*, (1923) **15**, 1173.
2. McAdam: *Heat Transmission*, p. 30ff, New York, (1933), McGraw-Hill.
3. Arnold: *J. Am. Chem. Soc.*, (1930) **52**, 3943ff.
4. Sage and Lacey: *Trans.* AIME (1939) **132**, 120.
5. Sage and Lacey: *Ind. Eng. Chem.*, (1936) **28**, 249.

DISCUSSION

By Michael J. Rzasa, Stanolind Oil and Gas Co., Tulsa, Okla., Member AIME

Espach and Fry are to be commended on publishing material which shows the change in physical characteristics of crude oil in a unit reservoir with elevation. However, there are several statements and conclusions in their paper which are worthy of attention.

In Table III, the authors have shown the hydrogen sulfide content of liberated gas from oil samples from Well No. 1. These data show that during the first pressure increment of 1,250 to 835 psia, the hydrogen sulfide content of the gas decreased from 7.6 to 5.1 per cent. Inspection of equilibrium vaporization constants for hydrogen sulfide would indicate that these results are to be expected in the particular pressure range under consideration. As further expected, the hydrogen sulfide content of further gas increments increases with pressure reduction. I am not sure what the authors mean by stating that the hydrogen sulfide content of the gas from the oil in the upper part of the reservoir would increase with pressure decrease, provided the gas-oil ratio during production did not exceed that in solution in the oil, and that increasing gas-oil ratios would result in decreasing the hydrogen sulfide content of the produced gas, because any volume of gas in excess of that in solution in the oil will contain smaller percentages of hydrogen sulfide than the solution gas. The amount of hydrogen sulfide which will come out of solution with pressure decrease is determined not only by the absolute amount of oil which releases this gas, but also by the vaporization characteristics of hydrogen sulfide. Since all the other components in the released gas will increase in absolute amount as the producing gas-oil ratio increases, it would seem to me that the hydrogen sulfide content would not necessarily decrease, but would appear in approximately the same proportion as given in Table III.

One point of great significance is the statement of the authors that their work proves that equilibrium in the Elk Basin Sand has not been attained. This conclusion is based on the fact that the physical characteristics of the oil from the deeper wells differ considerably from those upstructure. The change in elevation between Well No. 1 and Well No. 9 is approximately 1,750 ft. The very fact that there is this change in physical characteristics of the oil with change in elevation shows that the conclusion reached by the authors is incorrect. Thermodynamic equilibrium demands that this change in properties occur with change in elevation.

In ordinary engineering work it is customary to assume that pressure, temperature, and the composition of a phase are the independent variables sufficient to define the state of the system. This conclusion ignores gravitational and other types of energy associated with the system and it assumes that the pressure is uniform on the system. Stated in other words, when gravity is taken into account, the phase rule is no longer $f = c + 2 - p$, but becomes $f = c + 3 - p$.

Under equilibrium conditions, the chemical potential or molal free energy of all components must be equal to zero. It can be shown from thermodynamics that relationship exists between the change in composition of a fluid and change in elevation under isothermal conditions. Previous publication of calculations on a Dominguez Field crude oil show that for a change in elevation of 2,000 ft, the bubble point of the oil at 160°F changes approximately 885 psi. Furthermore, the isothermal effects indicating change in composition with elevation would be expected to be enhanced by a gradual increase in temperature as depth is increased.

With deeper depth, the crude oil will contain higher proportions of the heavier components and consequently a lower bubble point. With greater proportion of heavier components in a crude oil, the gas in solution and the relative oil volume will also decrease as depth from some datum is increased. Obviously, with increase in pressure the density of the oil will increase and the specific gravity of the gas in solution will also increase. These qualitative conclusions are borne out by the data published by Espach and Fry, and further substantiate the statement that thermodynamic equilibrium does exist at Elk Basin.

It would be of significance and value if the chemical composition of the crude oil at various elevations in Elk Basin were published as a part of this paper in order that such thermodynamic calculations can be made.

AUTHOR'S REPLY TO MR. RZASA

M. J. Rzasa's comment that change in composition of reservoir oil with elevation is to be expected at conditions of thermodynamic equilibrium is correct. This does not, however, make incorrect the conclusions reached by the authors. The magnitude of change reported in the Elk Basin study between the properties of the reservoir oil from Wells 1 and 9, with some 1,750 ft difference in elevation, is many times too great to be consistent with changes expected at conditions of thermodynamic equilibrium. Although changes in liquid composition of the reservoir oil were not available to be compared with the change of composition as defined by thermodynamic equilibrium, it is apparent upon examination of Sage and Lacey's[5] sample calculations, showing such small changes in composition, that equilibrium is not the explanation for the changes in properties of the original oil in the Tensleep Reservoir of the Elk Basin Field. This is substantiated further by a study of the properties versus structure of the original reservoir oil in the Weber Reservoir of the Rangely Field, Colo.[2] The Weber sandstone at Rangely and the Tensleep sandstone at Elk Basin are geologically equivalent formations. Labora-

Table V — Composition as a Function of Depth, Based on Subsurface Oil Samples from the Weber Sandstone Reservoir, Rangely Oil Field, Colo.

Depth, ft[1]	Butanes and lighter, mol per cent liquid	Pentanes and heavier, mol per cent liquid
0	44.29	55.71
840	30.57	69.43
Change: 840	−13.72	+13.72

[1]Measured from gas-oil interface.

tory analyses of reservoir oil sampled at Rangely provided nearly identical change in oil properties, solution gas/oil ratio, saturation pressure, etc., per foot change of reservoir elevation with the change reported for the Elk Basin study. Considerably more data on composition of the reservoir oil were obtained for the Rangely samples, so that the change in composition of the reservoir oil samples might be compared with calculated change at conditions of thermodynamic equilibrium in the reservoir.

The change in mol per cent liquid composition of the butanes and lighter fraction of the reservoir oil calculated by use of equations defining thermodynamic equilibrium is shown in Table VI. This change will account for only one fourteenth of the actual change found by sampling, as shown in Table V. For the single component methane in the liquid phase, the calculated change was only one thirtieth of the actual change found by sampling. It is difficult to reconcile the magnitude

Table VI—Composition as a Function of Depth, Based on Calculated Effect of Gravitational Concentration of Components for the Weber Sandstone Reservoir Oil, Rangely Oil Field, Colo.

Depth, ft[1]	Butanes and lighter, mol per cent liquid	Pentanes and heavier mol per cent liquid
0	44.29	55.71
840	43.35	56.65
Change: 840	− 0.94	+ 0.94

[1]Measured from gas-oil interface.

of change of reservoir oil properties with elevation found at both Rangely and Elk Basin with conditions of the thermodynamic equilibrium. It is thought that the small changes in composition of the reservoir oil defined by thermodynamic equilibrium fix the limit toward which the Elk Basin Reservoir oil was approaching, but had certainly not reached at the time of discovery.

We believe that the change of 885 psi in bubble point as calculated by Rzasa from Dominguez crude oil data and due to 2,000 ft change in elevation at thermodynamic equilibrium is in error and that these data indicate a change of about 70 lb.

A few comments will be made to clarify the percentage hydrogen sulfide content of gas produced from wells as reservoir pressure declines. In Fig. 6 the upper curve is the percentage hydrogen sulfide content of the solution gas versus pressure as taken from Fig. 2 of the subject paper. A reservoir oil sample taken when the reservoir pressure is at any value between 1,880 psia (original pressure) and 1,250 psia (saturation pressure), when differentially liberated to atmospheric pressure, will yield solution gas of quantity equal to the solution gas/oil ratio at 1,250 psia pressure. This gas will contain 18.2 per cent hydrogen sulfide. A reservoir oil sample taken at any lower pressure, for instance, 600 psia will yield solution gas of quantity equal to the solution gas/oil ratio at 600 psia, and this gas will contain 23.7 per cent hydrogen sulfide. If the produced gas/oil ratio were only the solution gas/oil ratio, the percentage hydrogen sulfide would follow the upper curve of Fig. 6 as the reservoir pressure declines.

The lower curve of Fig. 6 is the hydrogen sulfide content of liberated gas. It is the information of Table III of the subject paper plotted versus mid-point pressures. This curve pro-

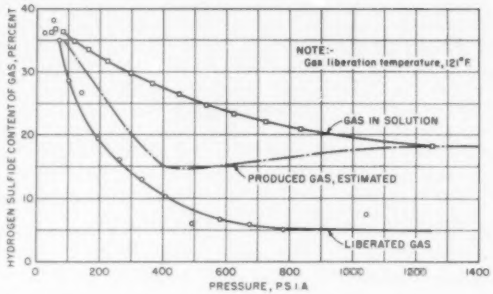


FIG. 6 — ESTIMATE OF PERCENTAGE HYDROGEN SULFIDE CONTENT OF PRODUCED GAS FROM WELL 1, ELK BASIN FIELD.

vides the percentage hydrogen sulfide content of a differential quantity of gas liberated from the reservoir oil sample for a small pressure decline. For example, as the pressure declines from 725 psia to 625 psia, gas will be liberated in a quantity equal to the difference in the solution gas/oil ratios at the two pressures and of approximately 5.9 per cent hydrogen sulfide content. This gas will be liberated in the reservoir.

If some of this free gas is produced from the reservoir in addition to the reservoir oil, the produced gas at the wellhead will be a mixture of solution gas from the reservoir oil and free gas from the reservoir. It is obvious that the percentage hydrogen sulfide in the produced gas will be reduced from the values of the upper curve of Fig. 6 by the free gas produced from the reservoir. A qualitative estimate of the variance of percentage hydrogen sulfide content of the produced gas with reservoir pressure is made in Fig. 6. The values trend away from the upper solution gas curve as free gas produced from the reservoir accounts for increasing percentages of the produced gas/oil ratios. This will occur as reservoir pressures are reduced from saturation pressure and will continue until the produced gas/oil ratios reach a maximum value. As the pressure is further reduced and the produced gas/oil ratios decline, the values will trend toward the upper "solution gas" curve. It is true that for the period of production characterized by extremely high produced gas/oil ratios the values will be nearly equal to the lower or "liberated gas" curve or the values of Table III of the subject paper. For the initial portion of the pressure decline the values will be more nearly equal the values of per cent hydrogen sulfide of the "solution gas" curve.

REFERENCES

1. Sage, B. H., and Lacey, W. N.: *Trans.* AIME, (1939), 132, 120.
2. Cupps, C. Q., Lipstate, P. H., Jr., and Fry, J.: U. S. Bureau of Mines Report of Investigations 4761, (1950). ★ ★

RELATIVE PERMEABILITY TO LIQUID IN LIQUID-GAS SYSTEMS

L. A. RAPOPORT AND W. J. LEAS, MEMBER AIME, THE CARTER OIL CO., TULSA, OKLA.

ABSTRACT

As a preliminary, consideration is given to the conventional definition of relative permeability and to the conditions governing the simultaneous flow of oil and gas through porous media.

For the conditions of flow prevailing throughout most of a gas drive reservoir, the oil and gas can reasonably be supposed to be in capillary equilibrium with each other. Under these conditions, and these conditions only, the relative permeability to liquid can be expressed as a function of saturation. The relative permeability to liquid in that case is dependent upon the distribution of fluids which itself is shown to be related to the capillary pressure, and, in turn, to the saturation. As a consequence, relative permeability to liquid can be expressed in terms of the volume and surface area of a network of liquid channels bounded by the rock and the gas phase. While the volume of this network can be evaluated accurately, the surface area cannot. However, for any such volume, maximum and minimum values of the corresponding surface area can be calculated from capillary pressure data. It is then possible to establish for any saturation the limits within which the value of the relative permeability to liquid must lie.

As a consequence of the theoretical development, the validity of an experimental method for measuring relative permeability to liquid which utilizes a stationary gas phase is demonstrated. In this method capillary barriers are cemented to the ends of the core sample to permit the maintenance of capillary equilibrium between the two phases. At the same time, this procedure eliminates undesirable secondary phenomena such as end effects, fissure effects, etc., the presence of which adversely affect the results of other laboratory methods.

The results obtained by theoretical calculations, and experimentally, are discussed. In view of the overall precision that can presently be obtained in reservoir calculations, the agreement between the calculated and measured relative permeability to liquid data can be considered satisfactory.

In conclusion, for reasons of economy and simplicity, the procedure of calculating limiting relative permeability to liquid curves from capillary pressure data is indicated for general engineering purposes. It is shown that the above procedure can easily be extended to the cases where connate water is present. Its use for reservoir studies is particularly recommended in conjunction with the method for measuring relative permeability to gas[1] which simultaneously yields the capillary pressure data necessary for the calculations.

THEORETICAL

Definition of Relative Permeabilities — Basic Equations for Heterogeneous Flow

The equations by which the relative permeability concept is defined and upon which the formulation of all of the gas-oil flow problems rests at the present time are expressed as:

$$V_L = \frac{k_L}{\mu_L} \text{ Grad } P_L = \frac{k K_L}{\mu_L} \text{ Grad } P_L \quad . \quad . \quad . \quad . \quad (1a)$$

$$V_G = \frac{k_G}{\mu_G} \text{ Grad } P_G = \frac{k K_G}{\mu_G} \text{ Grad } P_G \quad . \quad . \quad . \quad . \quad (1b)$$

where $_L$ and $_G$ refer to liquid and gas; V is the volumetric rate of flow per unit gross area, μ the viscosity, Grad P the potential gradient, and k the specific permeability of the porous medium.* (For horizontal flow, Grad P becomes the pressure gradient; otherwise, gravity must be included.) According to these expressions, each of the constituent phases is considered similar to a homogeneous system where the volumetric rate of flow is proportional to the pressure gradient, and for each of which the constants of proportionality, k_L and k_G, are termed effective permeabilities, by analogy to the specific permeability as defined by Darcy's law in its original form. In order to obtain a convenient basis of comparison, the effective permeabilities are referred to the specific permeability, k, of the considered porous medium, with the help of the relations:

$$k_L = K_L\, k$$
$$k_G = K_G\, k \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (2)$$

K_L and K_G are defined as the relative permeabilities to the liquid and to the gas phase respectively, and frequently expressed in per cent of specific permeability. It may be seen that Equations (1), which appear to be a direct generalization of Darcy's law, correspond to the assignment at any given time of a set of "local" permeabilities to each point of the porous medium, and represent in a differential form the two fluid flow system as a simple superposition of the individual single flow systems.

The above interpretation implies that the effective or relative permeabilities are independent of pressure or rate of flow,

[1]References given at end of paper.

Manuscript received at the office of the Petroleum Branch Aug. 23, 1950. Paper presented at the Petroleum Branch Fall Meeting in New Orleans, La., Oct. 4-6, 1950.

*Nomenclature at the end of the paper.

an assumption which appears to be substantiated by most of the experimental results. It seems reasonable, therefore, to consider at first the relative permeability concept on the basis of the conventional assumption (suggested by experimental observations), that relative permeabilities are functions of saturation only. The theoretical and experimental methods presented in this paper are confined to liquid-gas systems, for which it can be shown that each phase taken separately satisfies the conditions under which Darcy's law applies.

ANALYTICAL EXPRESSION FOR SPECIFIC PERMEABILITIES

Until recently the specific permeability, k, such as defined by Darcy's original relation

$$V = \frac{1}{\mu} k \text{ Grad } P \quad \ldots\ldots\ldots (3)$$

had to be considered as a purely empirical characteristic. A theoretical expression for Darcy's law and an analytical interpretation of the specific permeability were established by J. Kozeny in 1926.[2] His theory is essentially based upon a statistically homogeneous and isotropic distribution of the pore voids. It excludes any other simplifying assumption such as representing the porous medium by bundles of capillary tubes or by layers of spheres, etc., and leads to the final equation

$$V = \frac{1}{\mu} \cdot \frac{f^3}{t A^2} \cdot \text{Grad } P \quad \ldots\ldots\ldots (4)$$

where A is the interstitial surface area per unit of bulk volume, f the porosity, and t a textural constant. By identification of Equations (3) and (4), it is possible to express the total permeability as

$$k = \frac{1}{t} \frac{f^3}{A^2} \quad \ldots\ldots\ldots (5)$$

According to theoretical,[3] as well as numerous direct experimental results,[4,5,6,7] it appears possible to assign to the textural constant, t, the average value of 5, so that Equation (5) can be rewritten as

$$k = \frac{1}{5} \frac{f^3}{A^2} \quad \ldots\ldots\ldots (6)$$

Up to the present time, direct experimental checks of the Kozeny equation had been carried out only for unconsolidated granular beds. However, with help of the thermodynamical approach presented in Appendix A, a more complete verification of the theory has been made. (See Appendix B.) It was found that on the average the values of permeability computed according to Equation (6) were within ±12 per cent of the corresponding experimental measurements. These results were established over the widest possible range of homogeneous core material, with permeabilities varying from 15 md to 17,000 md and porosities varying from 9.3 to 35 per cent. Its consistency can, therefore, be considered as a good confirmation of Kozeny's theory, as well as of the constant value to be assigned to the textural constant.

The important physical concept to be derived from Kozeny's theory is that the porous medium must essentially be considered as a "flow matrix" of irregular shape. All these irregularities do, however, statistically average so that the permeability is determined only by the inside area and volume as indicated by Equation (5). It is then possible to define the following conditions for the general application of Darcy's law, and for its extension to multiphase systems:

(a) Continuity of the pressure gradient, which requires the continuity of the flowing phase throughout the system.

(b) Microscopically steady flow pattern, *i.e.*, laminar flow — as opposed to turbulent or oscillatory regimes.

(c) Existence of a flow matrix defined by its inside surface area and volume per unit of bulk volume.

CORRELATION OF THE RELATIVE PERMEABILITY FUNCTIONS AND FLUID DISTRIBUTIONS

Fluid Distribution at Static Equilibrium

Since the specific permeability depends exclusively upon the structural properties of the porous medium, the study of relative permeabilities must include consideration of the spatial distribution of each of the phases.

When two fluids in a given proportion, or under given externally imposed conditions occupy a porous medium, their distribution at static equilibrium is determined by surface energy relations. These surface energy relations are best visualized with the help of the phenomena pertaining to interfacial tension and contact angle. The contact angle determines the curvature of the interface between two immiscible fluids which, under the influence of the interfacial tension gives rise to the capillary pressure. Under static conditions, stable equilibrium is attained when the external forces such as gravity, or artificially imposed pressure, upon one of the phases are balanced by those of capillary pressure. For a given capillary pressure (*i.e.*, to that which is required to balance the external forces) there is a corresponding curvature, the same for all the existing interfaces. Considering then the geometry of the porous medium, it is seen that for a given curvature, there must correspond a certain position of the interfaces, *i.e.*, a definite microscopic fluid distribution and a definite saturation. As a consequence, it can be anticipated that inside the porous medium each constituent phase has a definite geometrical form determined by the saturations.*

In order to obtain quantitative results based on the above descriptive picture, the thermodynamic aspects of the capillary equilibria must be considered. Stable equilibrium at a given saturation corresponds to the minimum level of free energy — in this case free surface energy — that can be reached. The first condition for stable equilibrium is that each of the constituent phases be continuous. Furthermore, in a two fluid system, the "wetting" fluid is the one which has the smaller tension of adhesion against the rock. Consequently, at stable equilibrium the wetting fluid has to be distributed in such a

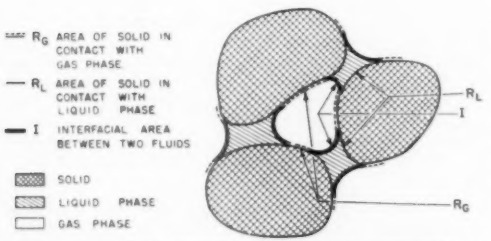


FIG. 1 — HYPOTHETICAL REPRESENTATION OF FLUID DISTRIBUTION IN RESERVOIR.

*Such a relationship can exist only under conditions of stable equilibrium, since hysteresis phenomena exclude the possibility of defining capillary pressure in an unequivocal manner.

way as to cover always the greatest possible surface of solid. On the other hand, the non-wetting fluid will be distributed in such a manner as to cover the smallest possible surface of the solid, and, at the same time, to expose the smallest possible interfacial area to the wetting fluid. It may then be seen that for a gas-liquid system the liquid having a tendency to preserve the greatest contact area with the solid will always fill the smaller pore openings, whereas the gas remains in the larger ones.

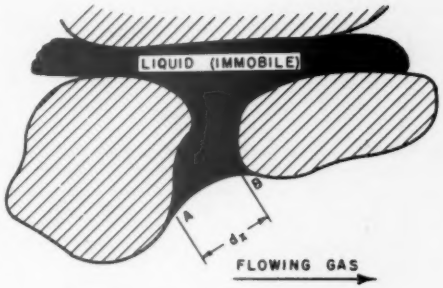
Fig. 1 illustrates in a schematic way the areas referred to above for which the following relationships can be established:

$A_L = R_L + I$ = Total surface area of the liquid (wetting fluid) system.

$A_G = R_G + I$ = Total surface area of the gas (non-wetting fluid) system.

$A = R_G + R_L$ = Total surface area of the solid system, *i.e.*, total grain surface. . . . . (7)

where R_L represents the contact area between the solid and the liquid, R_G the contact area between the solid and the gas, and I the interfacial area between the two phases.



CAPILLARY PRESSURE AT A = P_C

CAPILLARY PRESSURE AT B = $P_C - \frac{\delta P_C}{\delta X} dX = P_C - dP_C$

FIG. 2 — EFFECT OF FLOW ON THE EQUILIBRIUM OF AN INTERFACE.

Extension of Static Fluid Distribution to Flow Conditions; Definition of Parallel Flow

At static equilibrium, the distribution of two fluids in a porous medium depends essentially on the position of the interfaces, and as long as the pressure drop across a given interface remains constant, neither its shape nor its position will be changed. If, starting from a given static capillary equilibrium, flow is produced, a pressure gradient giving rise to this flow is established in each phase. For each interface this "flowing" pressure gradient may be considered as a local disturbance that is superimposed on a previously existing static equilibrium of capillary forces. Hence, the pressure drop across each interface, instead of being constant, over the entire interface varies from one point to another (see Fig. 2). Each interface will, therefore, have a tendency to modify its position in such a way as to equilibrate the resultant effect of the previously existing static pressure and the superimposed pressure variation corresponding to the flowing pressure gradients. Under conditions of steady state flow, it may be visualized that each interface will establish itself in a position of "dynamic equilibrium." Theoretically, this position is different from that of static equilibrium; however, for the purpose of analysis it is admissible to treat that type of flow for which the "disturbing" action of the flowing pressure gradient is negligible. Such an approach is justified whenever the flowing pressure gradient is sufficiently small in comparison to the capillary pressure, which is actually the case under most of the practical field conditions.

The flowing pressure gradients that usually prevail over the greatest part of natural reservoirs have a maximum of some pounds per foot, for instance 10 psi/ft. The dimensions of the interfaces can be considered as being of the same order of magnitude as those of the pore openings, *i.e.*, 1/10 mm as a maximum (in homogeneous media). That means that the change in capillary pressure, dP_c, resulting from the flowing pressure gradient over the dimensions of a given interface will in the average not exceed 1/300 psi. The capillary pressure itself, however, that establishes across the interface, is usually of the order of one psi and certainly no less than 0.3 psi. Consequently, the ratio dP_c/P_c which indicates the relative importance of the local disturbance, can always be expected to be smaller than 0.01 and may, therefore, be neglected as far as the micromechanism of flow is concerned.

For reasons of simplicity, one of the fluids had been assumed to remain stationary. In most cases, however, both fluids are flowing in the same direction, so that the actual dynamic disturbance is due to the difference of the flowing pressure gradients and might be still smaller than indicated above.

The above example shows that when the flowing pressure gradients are an order of magnitude smaller than the capillary pressure, and when the flow originates from a condition of stable (static) capillary equilibrium, the distribution of the flowing fluids remains stable and the same as at static capillary equilibrium. The movement of the ases can then be visualized as if they were flowing in an independent manner through two interwoven but distinct networks of channels. These networks, bounded partly by rock and partly by the other fluid, can be considered as extending "in parellel" throughout the system. Such a situation will be referred to as "parallel flow." It is a generalization of the concept of laminar flow in hydraulics, which defines a steady state streamline pattern.

In the reservoir (and in many laboratory experiments), the liquid saturation generally decreases in the direction of flow; furthermore, there is usually an overall (slow) decrease of saturation with time. However, once it has been recognized that the perturbation due to flow is small enough so as not to modify locally the nature of the capillary equilibrium phenomena, one can consider this perturbation as a differential element causing the saturation and fluid distribution to vary as continuous functions of space and time. It is then always possible to divide the total space into sufficiently small portions for each of which rigorously parallel flow can be admitted, if sufficiently small time intervals are considered. It is concluded that any heterogeneous flow system can be treated as a succession in time and space of "elementary" parallel flows, if throughout the system the saturation varies in a continuous manner (with time and space) and capillary equilibrium is preserved.

ANALYTICAL EXPRESSION FOR RELATIVE PERMEABILITY TO LIQUID

Referring to the conditions of applicability of Darcy's law, it is readily seen that in the case of parallel flow, such as described above, Darcy's law can be extended to each of the constituent phases; hence, Equation (5) can be applied to the liquid phase in the following manner:

(a) The replacement of the absolute porosity, f, by Sf — the

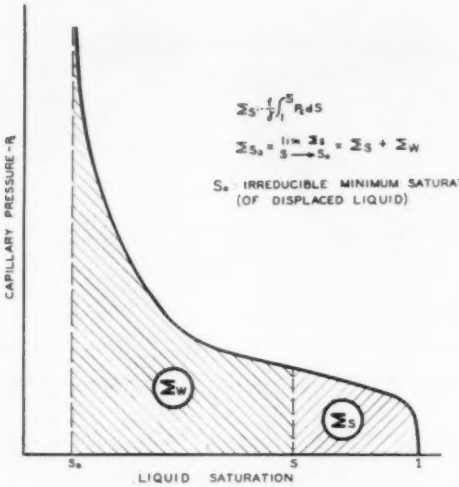


FIG. 3 — EXAMPLE OF CAPILLARY PRESSURE CURVE.

liquid filled pore volume per unit of bulk volume, *i.e.*, by the "effective porosity" with respect to the liquid.

(b) The substitution of the inside pore area, or total grain surface, A by A_L, which represents the total boundary area of the liquid phase "flow matrix."

By substitution of the above terms into Equation (5), the effective permeability to the liquid phase is obtained

$$k_L = \frac{S^3 f^2}{t A_L^2} \quad \ldots \ldots \ldots \ldots \quad (8)$$

and division of Equation (8) by Equation (5) gives the expression for relative permeability to liquid

$$K_L = \frac{S^3}{\left(\frac{A_L}{A}\right)^2} \quad \ldots \ldots \ldots \ldots \quad (9)$$

In order to obtain a more usable expression for the relative permeability to liquid, the following considerations must be taken into account. It is generally recognized that toward the end of a capillary displacement process an irreducible minimum saturation, S_o, is reached,[5] and no more liquid can be forced out, except by diffusion (the effects of which will be considered as negiligible in the present treatment). At this saturation the effective permeability to liquid becomes zero. Therefore, it seems logical to treat in first approximation the irreducible liquid as an essentially stationary element which reduces the porosity of the porous medium as well as the volume of flowing liquid. Once this liquid is considered as part of the solid framework, it is necessary to use an "effective" area, A_E, representing the surface that separates the flowing fluid from the immobile flow matrix composed of solid and stationary fluid, instead of the specific solid surface, A; furthermore, instead of using the total liquid saturation, S, a "reduced saturation," S', has to be introduced.

$$S' = \frac{S - S_o}{1 - S_o} \quad \ldots \ldots \ldots \ldots \quad (10)$$

On substitution into Equation (9) the following expression for the relative permeability to liquid is then obtained:

$$K_L = \frac{S'^3}{\left(\frac{A_L}{A_E}\right)^2} = \left(\frac{S - S_o}{1 - S_o}\right)^3 \left(\frac{A_E}{A_L}\right)^2 \quad \ldots \quad (11)$$

It will be noted that the derivation of Equation (11) implies the two following assumptions:

(a) The molecular layers at the interfaces between solid/liquid and gas/liquid are stationary. If they were not, the basic Kozeny treatment should be slightly modified so as to take into account a certain "slippage" of the fluid on part of its boundaries.

(b) The textural constant of the wetting fluid "matrix" is the same as that of the total pore space. Such an approximation seems to be justified since in general the possible variations of the textural constant have been recognized to be comparatively small.

EVALUATION OF LIMITING RELATIVE PERMEABILITY TO LIQUID FUNCTIONS FROM CAPILLARY PRESSURE DATA

The calculation of K_L, the relative permeability to liquid, requires a knowledge of the surface areas, A_L and A_E. With the help of a thermodynamic approach indicated in Appendix A, the following expressions can be derived from a liquid/gas capillary pressure curve:

$$A_G = \Sigma_S = -\frac{f}{\gamma} \int_1^S P_c dS \quad \ldots \ldots \quad (12)$$

$$A_E = \Sigma_{S_o} = -\frac{f}{\gamma} \int_1^{S_o} P_c dS \quad \ldots \ldots \quad (13)$$

$$A_L = \Sigma_w + 2I = -\frac{f}{\gamma} \int_S^{S_o} P_c dS + 2I \quad \ldots \quad (14)$$

in which the integrals indicate the areas under the P_c vs. S curves measured between the indicated limits (see Fig. 3). It is seen that a system of three equations is obtained for the four unknowns A_G, A_E, A_L, and I. Consequently, while the values for A_G and A_E are directly indicated, separate solutions cannot be defined for A_L or I.

In order to evaluate A_L, it is necessary to introduce an additional assumption concerning the distribution of the fluids. Such an assumption, expressed in terms of R_G, R_L, and I, will then represent one more independent equation, which together with the above relations will furnish a system from which all the unknowns can be solved. It might be recalled that on the basis of thermodynamic considerations only a more or less complex "trend" could be indicated for the liquid distribution, namely maximum contact area with the solid compatible with a minimum amount of interfacial area. In order to express such a trend in a more exact manner, it would be necessary to consider in detail the geometry of the porous medium, which depends on very many parameters such as grain size distribution, sphericity or shape factor of the grains, packing, consolidation, etc. Obviously, at the present time, it is impossible to treat such a geometrical complex in a general and precise way. Therefore, no exact additional relation can be established that would lead to unique solutions for A_L and I. The only logical approach that can be attempted consists of establishing the most general limiting conditions of fluid distribution that could be expected to apply to any, or at least

to most, of the possible geometrical systems. According to such a principle, separate calculations for the minimum and for the maximum values of K_L will be shown.

Evaluation of Limiting K_L Minimum Function

In accordance with the previously established relations, Equations (7), (12), and (14), the following system of equations can be considered:

$$\Sigma_w = A_L - 2I \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (15)$$

$$\Sigma_s = R_G + I \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (16)$$

where Σ_s and Σ_w have a well defined value at any saturation and can, therefore, be considered as "constants" in regard to the unknowns A_L, I, and R_G. It is readily seen that according to Equation (15) for any set of Σ_s and Σ_w, *i.e.*, for any saturation, a maximum value will be obtained for A_L if I is maximum and that according to Equation (16) the maximum for I obtains if R_G is assumed to be zero. Consequently, the maximum value that A_L may take at any saturation is

$$A_L \text{ (Max.)} = \Sigma_w + 2\ \Sigma_s = \Sigma_{s_o} + \Sigma_s \quad . \quad . \quad (17)$$

According to Equation (11) it is clear that at any saturation the smallest possible value will be obtained for the relative permeability to liquid, K_L, if a maximum area, A_L, is considered, so that

$$K_L(\text{Min}) = S^{n} \left[\frac{A_L}{A_L(\text{Max})} \right]^n = S^{n} \left[\frac{\Sigma_{s_o}}{\Sigma_{s_o} + \Sigma_s} \right]^n \quad . \quad (18)$$

Physically the derivation of K_L(Min) means that the distribution of the fluids is such as not to permit the existence of any contact between the gas phase and the solid surface. The gas can then be visualized as flowing inside a network of channels completely surrounded by liquid, as schematically represented in Fig. 4, and it might be noticed that such an assumption concerns only the disposition of the fluids, and does not correspond to any hypothesis about the geometry of the porous medium itself.

Evaluation of Limiting K_L Maximum Function

Referring to the system of Equations (15) and (16), it is seen that the theoretical absolute minimum value for A_L would obtain under the assumption $I = 0$, *i.e.*, $A_L = \Sigma_w$. Such a situation would correspond to $R_G = A_G$, *i.e.*, to the assumption of having the gas phase — and equally the liquid phase — bounded exclusively by solid surfaces. In that case, the porous medium should be visualized as formed by non-interconnected capillaries. It is clear that such an assumption is by far too limiting and leads actually to K_L values which are too high. Thus, instead of considering — even for the purpose of limiting conditions — a porous medium as equivalent to a bundle of capillary tubes, it is reasonable to represent it as an isotropic random packing of grains. Under this more general assumption, interfaces must exist between the gas and liquid, and none of the three surface areas, I, R_G, R_L is zero. The lowest possible value of the ratio I/R_G can then be evaluated. The use of this value in Equation (16) leads to a minimum value of I, of A_L, and consequently, to a maximum of K_L.*

With the help of general capillary pressure relationships, it is possible to show that

$$\frac{I}{R_G} > \frac{Sf}{1-f} \left(\frac{P_m}{P_c} \right)^2 \quad . \quad . \quad . \quad . \quad . \quad (19)$$

where P_c represents the capillary pressure at any saturation, S, and P_m the mean value of P_c corresponding to the saturation range S to S_w. The above inequality leads to the following minimum value of A_L:

$$A_L(\text{Min}) = \left[\Sigma_w + \frac{2\ \Sigma_s}{1 + \frac{1-f}{Sf} \left(\frac{P_c}{P_m} \right)^2} \right] \quad . \quad (20)$$

and the final expression for the limiting maximum relative permeability to liquid is then obtained as

$$K_L(\text{Max}) = S^{n} \frac{\Sigma_s^{\,2}}{\left[\Sigma_w + \frac{2\ \Sigma_s}{1 + \frac{1-f}{Sf} \left(\frac{P_c}{P_m} \right)^2} \right]^2} \quad . \quad . \quad . \quad (21)$$

EXPERIMENTAL

Principle of the Method

The experimental method has been conceived so as to measure the relative permeability to the liquid phase under the conditions of parallel flow defined previously. According to

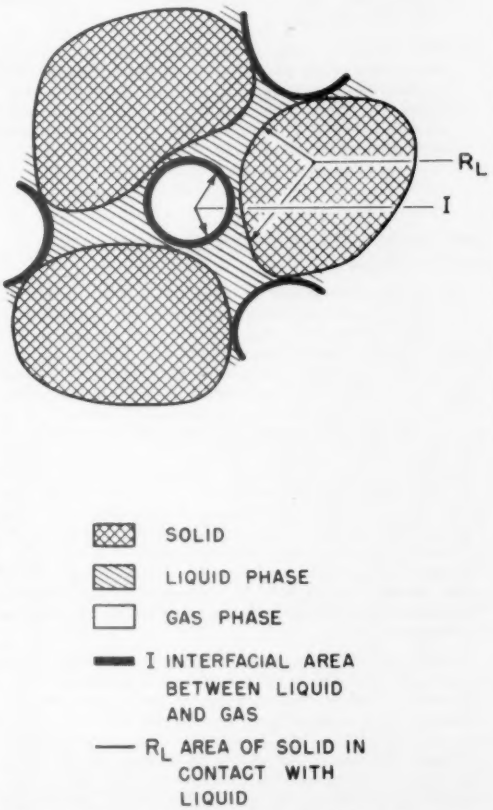


FIG. 4 — SCHEMATIC REPRESENTATION OF COMPLETE GAS CHANNELING.

*The detailed treatment for the derivation of K_L maximum is indicated in Appendix C.

these conditions, capillary equilibrium must be maintained between the two phases throughout the entire core specimen. The main difficulty in obtaining such an equilibrium results mostly from different sorts of "end-effects," the influence of which extends back into the core. In the experimental method presented, the capillary pressure between gas and liquid is established by means of semi-permeable barriers, and controlled by the pressure imposed upon the gas. The elimination of secondary phenomena as outlined above is obtained by cementing the capillary barriers, permeable to liquid only, to each end of the core sample. The experimental procedure can then be outlined as follows:

(1) The ensemble of core and end plates is fully saturated with liquid.

(2) Through a central orifice in one of the end plates, gas is forced into the core and liquid is displaced through both the end plates until the system comes to equilibrium, *i.e.*, reaches a saturation which corresponds to the capillary pressure that has been imposed upon the gas.

(3) The liquid is then allowed to flow through the system, whereas the gas remains immobile, held back by the semi-permeable barriers. The flowing pressure gradient in the liquid is kept constant and sufficiently low so as not to disturb the capillary equilibrium and the previously established saturation.

(4) When perfectly steady state conditions are reached, the exact values of the pressure drop in the liquid over the length of the core sample and the rate of flow are determined. The effective and, consequently, the relative permeabilities are then obtained and plotted against the corresponding saturation.

Description of Experimental Apparatus and Procedure

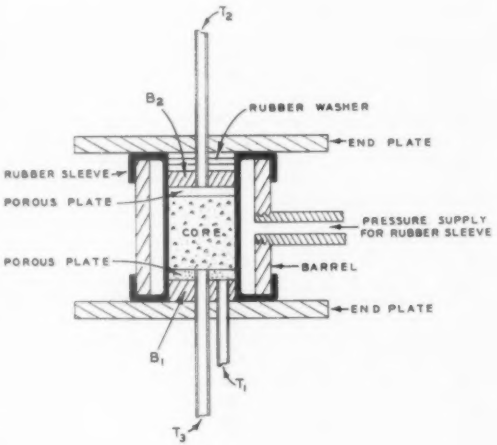
The relative permeability to liquid cell is shown in Fig. 5. In general construction it resembles the relative permeability to gas cell[7] and many of the parts are interchangeable. Not shown in the diagram are the "O" ring seal between tube T3 and the porous plate, and the grooves in the face of the metal plates B1 and B2 for the distribution of liquid to the porous plates. These grooves ensure that the liquid phase is free to move unidirectionally through the core, thereby eliminating any divergent or convergent flow except in the immediate vicinity of the gas inlet tube T3. The ratio of the area of the end of this tube to the cross sectional area of the core is 1/64 so that any resulting perturbations in the flow pattern are negligible. Gas is admitted to the core through the tube T3, which is connected to a gas pressure source and to a manometer with which the pressure of the gas phase is measured. Liquid enters the cell through tube T1 and leaves through tube T2. These tubes are connected through a commutating valve to the flowmeter.

The flowmeter consists of two precision-bore calibrated glass tubes which are side by side in the same horizontal plane. The right end of one tube and the left end of the other are connected to a commutating valve. Liquid fills only a portion of each tube and the application of gas pressure to the gas-liquid interface in one of the tubes causes the liquid in that tube to flow through the core into the other tube. When the first tube is nearly empty of liquid, the gas pressure to that tube is released, the commutating valve is turned, and the gas pressure is applied to the second tube, which is now nearly full of liquid. It, in turn, is emptied and the liquid reappears in the first tube. This cycle can be repeated indefinitely and though sizable volumes of liquid can be passed through the core, only a few milliliters of liquid are required. The fact that the liquid-gas interfaces in the tubes are in the same horizontal plane eliminates any gravitational gradient in the liquid phase, and only the differential gas pressure acting on the interfaces needs to be measured to determine the pressure gradient causing flow in the liquid phase.

The commutating valve permits the reversal of fluid flow in the flowmeter tubes while maintaining at all times the same direction of flow within the core. A bleeder valve in one of the flowmeter lines permits the adjustment of the volume of liquid within the system. Since the two flowmeter tubes are parallel and of the same internal diameter, the two interfaces move at the same rate and in the same direction when liquid is flowing through the core under steady state conditions. By measuring the velocity of the interfaces and the differential gas pressure acting upon them, the effective permeability of the core under test can be calculated.

The flowmeter also indicates the amount of liquid expelled from the core. At the start of the relative permeability measurement the liquid saturation of the core is unity and the differential linear separation of the interfaces is noted. As long as the liquid saturation of the core remains fixed, the separation of the interfaces remains constant. When the gas pressure applied through the gas inlet tube T3 exceeds the threshold pressure of the core, liquid is expelled from the core and appears in the flowmeter tubes as a change in the separation of the interfaces. This permits the calculation of the liquid saturation of the core at any time. A scheme similar to this has recently been described.[8]

Several factors must be considered in the selection of the plates which function as semi-permeable barriers. Firstly, the



T_1 & T_2 = FLOW TUBES FOR LIQUID PHASE
B & B_1 = BACKING PLATES
T_3 = TUBE FOR GAS PHASE

FIG. 5 — RELATIVE PERMEABILITY CELL.

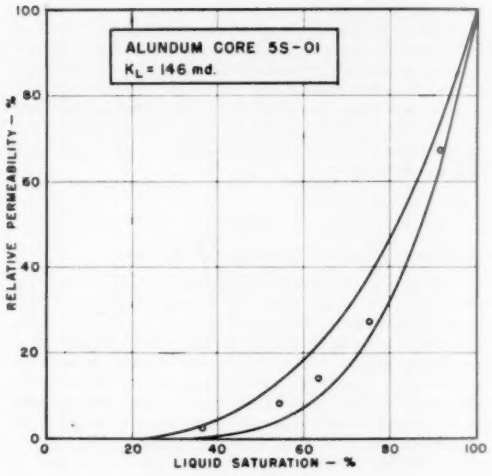


FIG. 6

pore size of the plates must be such that they remain fully saturated with liquid at all gas pressures to which they are exposed. Secondly, they must have as high a transmission coefficient to liquid as is possible (in conformity with the first requirement) so that changes in the relative permeability of the core will not be unduly suppressed. This can, in part, be accomplished by using thin plates, yet they must remain thick enough to withstand breakage. The elimination of undesirable "fissure effects" is accomplished by cementing the plates to the core.

After the core to be tested has been cut to shape and extracted, its pore volume and permeability (to n-decane) are measured. It is dried and the porous end plates are cemented in the following manner. The core and plates are fully saturated with water. A plaster of Paris slurry is spread over one side of the outlet plate, which is pressed against the end of the core to expel the excess plaster of Paris.* The core with outlet plate is dried and its permeability to n-decane is measured. It is redried and the inlet plate is cemented in the same manner as was the outlet plate. The ensemble is then put into the cell where its liquid permeability is determined at a liquid saturation of unity.

Air, under pressure, is then admitted to tube T3 and a portion of the liquid in the core is expelled into the flowmeter. When equilibrium is reached, the differential separation of the interfaces in the flowmeter tubes becomes zero and the permeability of the ensemble at a liquid saturation less than unity is measured. The air pressure in T3 is again increased and the cycle is repeated until the permeability of the ensemble falls to a value too low to be measured. From these measurements the effective permeability of the core and end plates is obtained, and the relative permeability can then be determined for each corresponding liquid saturation.

*This procedure of saturating the core prior to affixing the plates minimizes the possibility of plugging the core through movement of the plaster slurry into the core if it were applied to a dry core. The liquid permeability of a core whose porous plates were attached in this manner was found to be unchanged after their removal.

RESULTS AND DISCUSSION

Results

The results obtained with n-decane and air using three alundum cores and three natural cores are shown in Figs. 6 to 11. The solid curves are the limiting K_L values calculated from displacement data obtained on these cores using a single-core displacement cell[10] with decane displaced by air. The limiting curves for the three alundum cores are much the same. This is to be expected since their capillary pressure curves were similar. With the exception of two points on Core 59A-15, the data fall within the limiting values. The agreement between the calculated and experimental data for the alundum cores is good for each core.

In considering the three natural cores, it is seen that the limiting K_L values vary widely both as to position and spread. Here again their position is determined by the shape of the capillary pressure curve. Generally, it has been observed that a capillary pressure curve of near zero slope which undergoes a sharp transition to a vertical slope at the minimum saturation results in a large spread between the calculated K_L limits, whereas capillary pressure curves which have an appreciable slope even at high liquid saturations usually result in a very narrow spread of the limiting K_L values. Considering the narrow spread, the agreement is good for the Bohanon core. Three runs were made on the Elk Basin core and the results cluster about the lower limiting curve. No single run has points which lie either entirely above or below the lower curve. The Bartlesville core has narrow limits and the experimental data which seem to be slightly S-shaped fall partly outside the limits. On the whole, the agreement obtained with the alundum cores is better than that obtained with the natural cores. Although the exact reasons for this are not known, it is possible that the higher degree of homogeneity of the alundum cores is a contributing factor.

Although K_L results obtained by the Botset[11] and "Penn State"[12] methods might be regarded as questionable,[13] their rather extensive use warrants their mention. The results ob-

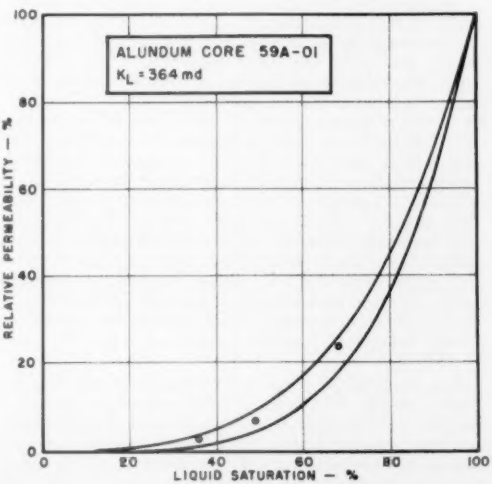


FIG. 7

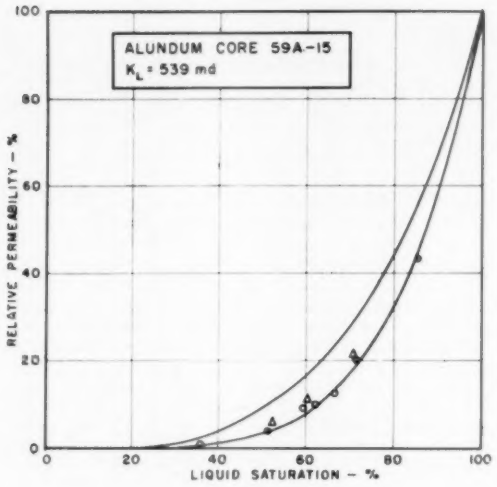


FIG. 8

tained by these methods on an unconsolidated sand and on a synthetic sandstone are shown in Figs. 12 and 13. The experimental points show greater scattering, which might be expected since no difference in pressure exists between the phases, so that appreciable "end effects" can be anticipated. The majority of the points, however, lie within the calculated limits.

DISCUSSION OF THE RESULTS

Validity of the Parallel Flow Concept

The theoretical and experimental methods presented in this paper for the determination of relative permeability to liquid are confined to the strict consideration of parallel flow mechanisms, *i.e.*, to the case where the flowing fluids remain in capillary equilibrium with each other. In most practical instances, it is recognized that parallel flow may be "perturbed" by secondary phenomena, mainly the release of gas bubbles. Such bubbles do not correspond to capillary equilibrium, and furthermore, cannot be subject to laminar flow. It can be anticipated, however, that in any point of the reservoir the existence of separate gas bubbles corresponds to a relatively short transient stage. Due to rapid diffusion effects and possible mechanical transportation, the separate bubbles have the tendency to reach stable capillary equilibrium and to merge into a continuous gas body. Recent experiments performed in this laboratory have indicated that (under atmospheric conditions) the time required in order to reach phase continuity — and consequently capillary equilibrium — is of the order of 24 hours.

It is clear that the formation of a continuous gas phase becomes possible only after a certain minimum amount of bubbles, corresponding to the "equilibrium gas saturation" has been released from solution. The phenomenon of equilibrium gas saturation must be considered as a determining factor for the flowing behavior of the gas phase, and it is for that reason that a theoretical derivation of the relative permeability to gas function has not yet been presented. For the liquid phase, the continuity of which can always be expected to be uninterrupted, it is however, a reasonable approximation to derive the relative permeability function under the assumption that capillary equilibrium exists throughout the entire range of saturation. Accordingly, for most practical purposes the use of the parallel flow concept and the application of the presented methods appears to be justified in the case of any liquid-gas flow system.

Discussion of the Experimental Method

In the presented experimental technique, undesirable features of other methods have been overcome. The use of cemented porous end plates permits the maintenance of a pressure difference between the gas phase and the liquid phase, and eliminates end effects and fissure effects. These latter correspond to a progressive invasion by the gas phase of the microscopically large voids which exist between the core and porous plates (or two adjacent core sections) as shown by direct-X-ray measurements.[14] Furthermore, there is no distortion of the flow pattern from linear flow since at the ends of the core there are no pressure taps or sizable areas for gas flow. The determination of the pressure gradient is subject to unequivocal measurement and is effective over the complete length of the core.

In the tests run by this method, the pressure gradients did not exceed a few centimeters of water. Under such conditions the use of an immobile gas phase is justified insofar as the theoretical discussions have shown that the relative permeability to liquid so obtained can be expected to be the same as though both phases were flowing.

It is recognized that due to the immobility of the gas, a saturation distribution exists throughout the core. The procedure of plotting directly the measured relative permeability of the core against its average saturation might, therefore, be subject to a systematic error. However, the small pressure

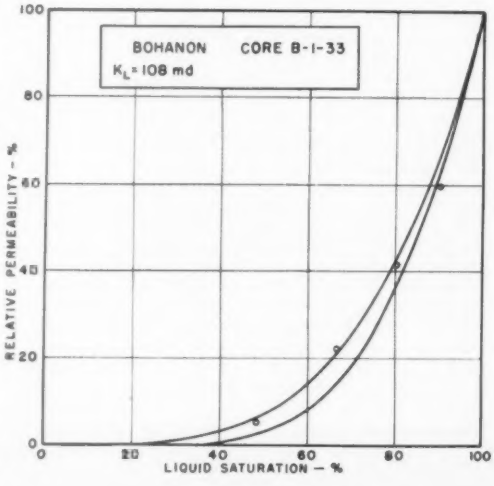


FIG. 9

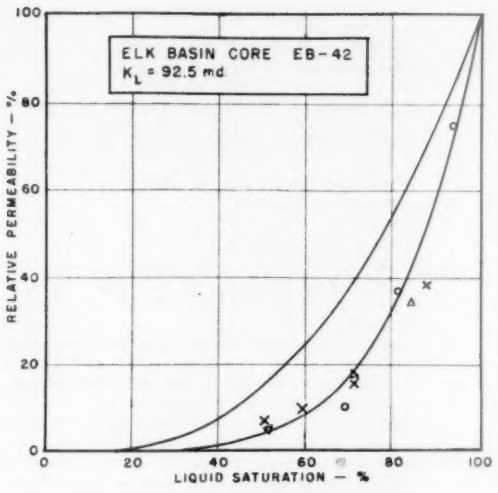


FIG. 10

gradients and rates of flow used in the present experiments preclude a large correction. To verify this, the points x in Fig. 10 were obtained using a pressure gradient which was twice that used for the other points. These points therefore correspond to a steeper saturation distribution. Since, however, the agreement between all the runs is very close, it appears that at the rates of flow used, the effect of any saturation distribution is very small.

Under identical experimental conditions, two separate runs were made using cores 59A-15, Fig. 8, and EB-42, Fig. 10. The results of the first run are indicated by circles and the second by triangles. All points lie within a narrow band no wider than would be expected on the basis of normal experimental deviations, so that the reproducibility of the method can be considered as satisfactory.

Validity of the Calculated Data

Since the limiting K_L functions are expressed essentially by the cube of the "reduced" saturation, $S' = S - S_w/1 - S_w$, they are very sensitive to the variations of the parameter, S_w, in the regions of low saturations, *i.e.*, when S approaches S_w. The determination of the proper irreducible minimum saturation, S_w, to be used in the calculations is comparatively delicate in view of diffusion effects, which can be quite important in liquid/gas systems. Both calculated limiting K_L curves might, therefore, be subject to a systematic error, namely too high, in the regions of low saturation, since the diffusion effects cause an apparent decrease of S_w. This effect is apparent in Figs. 8 and 10, and has been observed in several other instances.

The limiting K_L curves presented in this report were calculated from decane/air P_c curves. Although this is justified for the purpose of checking the calculated results against the direct K_L measurements (which were obtained on decane-air systems), the procedure should be slightly modified for practical application. It is necessary to take into account the possibility of swelling clay minerals frequently contained in natural cores. Strictly speaking, the calculations should, therefore, be based upon P_c curves obtained by the displacement of decane (or any other suitable hydrocarbon) by air in the presence of connate brine. However, it can be anticipated that sufficiently reliable results will be obtained by simply using the brine/air displacement curves that are usually available. Justification for such a procedure is indicated by recent experimental determinations of relative permeability to gas, which yielded practically identical results with and without having a "connate" liquid phase present.[1]

The fact that instead of calculating a unique K_L function, only limiting curves are determined, might be examined in the light of the overall degree of precision that can be obtained by the present techniques. In many cases it can be observed that the spread between the experimental data is of the same order of magnitude as that of the theoretical curves. Furthermore, in view of the sampling problems associated with petroleum reservoirs, the present need is actually for approximate data on a large number of reservoir cores rather than precise data on only a few. In many practical instances, the use of the theoretical limiting K_L curves might, therefore, be desirable. Engineering calculations can be carried out either by using separately the upper or the lower curve, or by constructing the average curve and determining (by comparison to the limiting curves) the maximum error introduced.

CONCLUSIONS

From the foregoing work the following conclusions are drawn:

(1) By means of a theoretical analysis of fluid micro-behavior, it has been shown that the relative permeabilities needed

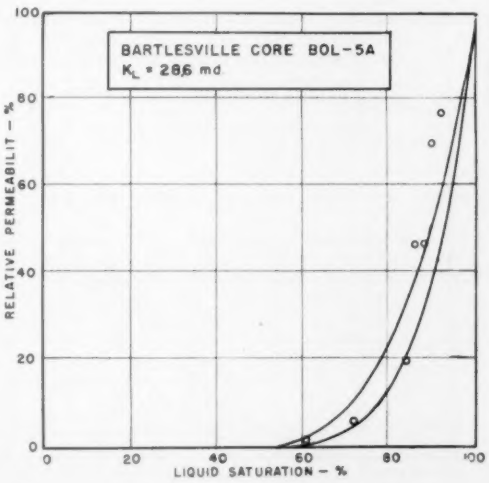


FIG. 11

for studies of liquid-gas reservoirs are directly related to the distribution of fluids and must primarily be functions of saturation.

(2) A procedure for calculating limiting K_L curves from capillary pressure data has been established. The possibility of applying the calculated curves to the case where connate water is present has been indicated.

(3) An experimental method based upon the use of cemented capillary barriers and upon the principle of an immobile gas phase has been developed for measuring the relative permeability to liquid. It has been shown that in the above method the undesirable phenomena such as end effects, fissure effects, etc., common to other types of procedures, have been eliminated.

(4) The general validity and the comparative simplicity of the experimental method have been demonstrated. It has been found that good agreement exists between the experimental and calculated data.

(5) For reasons of economy and simplicity, the calculation of limiting K_L curves seems indicated for routine engineering purposes. It is particularly recommended for use in conjunction with a method developed previously for determining relative permeability to gas,[1] which yields K_G and P_c data simultaneously.

ACKNOWLEDGMENT

The authors wish to thank the Carter Oil Co. for permission to publish this paper. They are particularly indebted to W. A. Bruce and Charles D. Russell for their valuable suggestions and helpful assistance during the course of this research and in the preparation of this report, and to Miss J. J. Hume for much of the experimental data and calculations.

NOMENCLATURE

(Symbols by Order of Appearance)

Usual Subscripts: L refers to liquid
G refers to gas
I refers to interfaces
S refers to saturation

- V — Volumetric Rate of Flow per Unit Cross Sectional Area
- k — Specific or Effective Permeabilities
- K — Relative Permeability
- P — Pressures
- μ — Viscosity
- f — Porosity
- t — Textural constant
- A — Total Boundary Areas (in cm² per cm³ of bulk volume)
- I — Interfacial Surface Area Between Liquid and Gas (in cm² per cm³ of bulk volume)
- R_L — Contact Area Between Liquid and Solid (in cm² per cm³ of bulk volume)
- R_G — Contact Area Between Gas and Solid (in cm² per cm³ of bulk volume)
- P_c — Capillary Pressure
- S — Liquid Saturation
- S_o — Irreducible Minimum Liquid Saturation as Obtained from Capillary Pressure Curve
- S' — Reduced Liquid Saturation
- Σ — Areas Under the Capillary Pressure Curve Times the Quantity $-(f/\gamma)$
- γ — Interfacial Tension Between Liquid and Gas
- F — Free Surface Energy
- θ — Contact Angle of Liquid Against Solid in presence of Gas

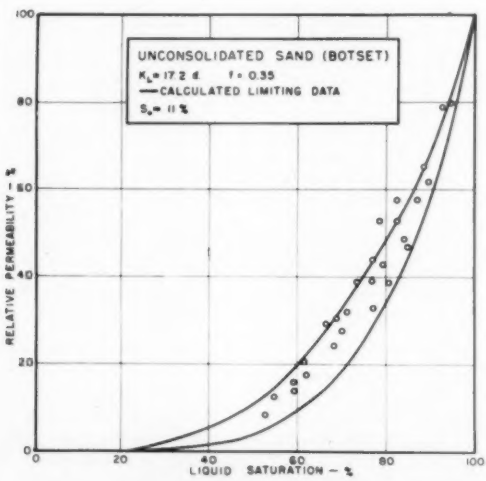


FIG. 12

REFERENCES

1. Leas, Jenks and Russell: *Trans.* AIME, (1950) **189**, 65.
2. Kozeny, J.: *Ueber Kapillare Leitung des Wassers im Boden*, Berichte der Wiener Akademie, (1927) **136A**, 271-306.
3. Fowler, J. L., and Hertel, K. L.: "Flow of Gas Through Porous Media," *Jour. of Applied Physics*, (1940) **11**, 496-502.
4. Schriever, Wm.: *Trans.* AIME, (1930) 329-336.
5. Traxler and Baum: *Physics*, (1936) **7**, 9-14.
6. Carman, P. C.: *Trans.* Inst. Chem. Engr., (1937) **15**, 150-166.
7. Coulson: University of London Ph.D. Thesis, "The Streamline Flow of Liquids Through Beds Composed of Spherical Particles," (1935).
8. Levertt, M. C.: *Trans.* AIME, (1941) **142**, 152.
9. Brownscombe, Slobod and Caudle: "Laboratory Determination of Relative Permeability," *Oil and Gas Journal*, Feb. 9 and 16, 1950.
10. Rose and Bruce: *Trans.* AIME, (1949) **186**, 127.
11. Wyckoff and Botset: "The Flow of Gas-Liquid Mixtures Through Unconsolidated Sands, *Physics*, (1936) **7**, 325.
12. Morse, Terwilliger and Yuster: "Relative Permeability Measurements on Small Core Samples," Mineral Industries Experiment Station, Technical Paper 124, Pennsylvania State College.
13. Henderson and Meldrum: "Progress Report on Multiphase-Flow Studies," *Producers Monthly*, (March, 1949).

14. Morgan, McDowell and Doty: *Trans.* AIME, (1950) 189, 183.
15. King, F. H.: "Principles and Conditions of the Movements of Ground Waters," *U. S. Geol. Survey*, (1897, '98), 2, 192.
16. Darapsky, Zeitschr: *Math. Phys.*, (1912) **60**, 170.
17. Siegel: *Der Chemie Ingenieur*, (Liepzig, 1933) **1**, Part 2.
18. Kozeny, J.: "Die Durchlässigkeit des Bodens," *Kulturtechniker*, (1932) 478.

APPENDIX A
THERMODYNAMICAL ASPECTS OF DISPLACEMENTS IN POROUS MEDIA

The capillary pressure curve obtained by displacing the wetting phase from an initially fully saturated porous medium may be defined as representing an isothermal equilibrium process, or more exactly, a succession of equilibria. The pressure on the non-wetting phase (gas) is increased in a stepwise fashion resulting in the gradual displacement of the wetting phase (liquid). As this equilibrium process takes place, it can be said that (a) the interfacial area between phases is varying in a continuous fashion, probably increasing until the irreducible minimum liquid saturation is reached, and (b) the solid/liquid contact area diminishes and is replaced by a solid/gas, or more exactly by a solid/liquid-film/gas area. For the total system formed by the liquid and the solid, the displacement process represents an isothermal-isobaric transformation. During such a transformation it is known that the external work done against the system (by the non-wetting gas phase) is equal to the increase of free energy of this system. The capillary pressure curve can thus be interpreted as representing the change of free surface energy that takes place in the porous medium during the displacement process.

Referring to the definition of surface areas as given by Equation (7), the change in free surface energy due to an increase of the interfacial area can be stated as:

$$dF_l = \gamma\ dl \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (A\text{-}1)$$

If during the process of desaturation, solid area previously covered by the liquid phase is covered by gas, the increase of the "solid-gas" contact area is dR_0, and the corresponding change in free surface energy can be stated as

$$dF_s = dR_0\ \gamma \cos\theta \quad . \quad . \quad . \quad . \quad . \quad . \quad (A\text{-}2)^*$$

Addition of Equations (A-1) and (A-2) obtains:

$$dF = dF_l + dF_s = \gamma\ (dl + dR_0 \cos\theta) \quad . \quad (A\text{-}3)$$

where γ represents the interfacial tension between the two fluids, and θ the contact angle. But dF is the total change in free (surface) energy corresponding to a change in saturation dS, and is, consequently, equal to the work Pdv done against the system, or if a core of unit bulk volume is considered:

$$dF = -P_c.f.dS = \gamma\ (dl + dR_0 \cos\theta) \quad . \quad . \quad (A\text{-}4)$$

In the case where the contact angle θ is zero, $\cos\theta = 1$, and

$$P_c.f.dS = -\gamma\ (dl + dR_0) \quad . \quad . \quad . \quad . \quad (A\text{-}5)$$

or

$$P_c\ f.dS = -\gamma.dA_0 \quad . \quad . \quad . \quad . \quad . \quad . \quad (A\text{-}6)$$

and

$$A_0 = -\frac{f}{\gamma}\int_1^S P_c\ dS \quad . \quad . \quad . \quad . \quad . \quad . \quad (A\text{-}7)$$

In explanation of the above equations, if, during the displacement process, eqnilibrium is not attained, or if an unstable film is left on the rock surface, the work of displacement may have a considerably different value than that indicated in the general Equation (A-4). Equilibrium is obtained, however, if the contact angle θ is zero, which is usually the case in liquid gas systems. The exact value of A_0 can be derived only if $\theta = 0$, since up to the present no relationship exists which would permit the separate identification of dl and dR_0.

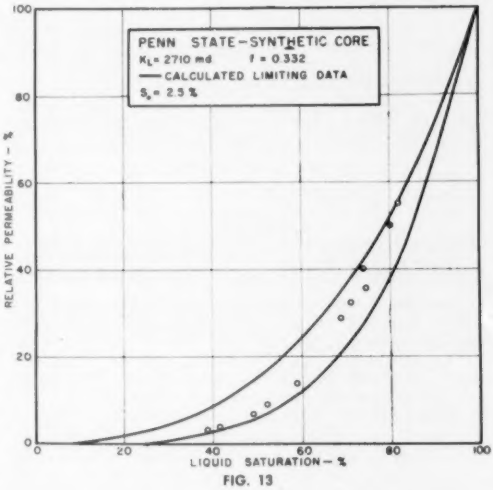


FIG. 13

Under the above circumstances, the areas under the capillary pressure curve can be assigned the following meanings (see Fig. 3):

$\Sigma_S = -\frac{f}{\gamma}\int_1^S P_c\ dS$ represents the interfacial area at the saturation S together with the rock area exposed to the non-wetting phase, less the amount, I_B, of interfaces that existed at the bulk surface of the fully saturated core; I_B is comparatively very small and can be neglected so that

$$\Sigma_S = -\frac{f}{\gamma}\int_1^S P_c\ dS = l + R_0 - I_B \simeq l + R_0 = A_0\ . \quad (A\text{-}8)$$

The maximum limiting value of the above integral can be represented by

$$\Sigma_{S_w} = -\frac{f}{\gamma}\int_1^{S_w} P_c\ dS = R_{0(LIM)} + I_{(LIM)} \quad . \quad . \quad . \quad (A\text{-}9)$$

In this expression $I_{(LIM)}$ represents the interfacial area between the gas and the "connate" liquid, and consequently $R_{0(LIM)}$ the (maximum) gas/solid contact area that obtains at the irreducible minimum liquid saturation. On the basis of considering the connate liquid as being immobile, it is seen that Σ_{S_w} which corresponds to the envelope of the connate liquid and solid area, represents the surface area A_R of the total effective flow matrix,* so that

$$\Sigma_{S_w} = -\frac{f}{\gamma}\int_1^{S_w} P_c dS = A_R = R_0 + R_L \quad . \quad . \quad . \quad (A\text{-}10)$$

*This relation implies that the receding liquid leaves a fi'm over the solid surface. It is, however, understood that the liquid particles of this molecular film have no actual bearing upon the distribution and the flow mechanism of the fluids.

*Such an interpretation is equiva'ent to treating I_{LIM} as part of the total "solid" area, which always remains covered by the liquid phase and is, therefore, automatically included in R_L at any saturation.

Is is then finally seen that

$$\Sigma_\pi = \Sigma_{S_o} - \Sigma_S = -\frac{f}{\gamma}\int_S^{S_o} P_c dS = A_E - R_G - I \quad . \quad \text{(A-11)}$$

or, combining Equations (A-10) and (A-11)

$$\Sigma_\pi = R_L - I = A_L - 2I \quad . \quad . \quad . \quad . \quad . \quad . \quad \text{(A-12)}$$

The above derived relations (A-8), (A-10), and (A-12) are used for the derivation of K_L(Max) and K_L(Min).

APPENDIX B
CALCULATION OF SPECIFIC PERMEABILITIES FROM CAPILLARY PRESSURE DATA

According to the derivations presented in the Main Report and in Appendix A, the specific permeability of a porous medium can be expressed as

$$k = \frac{1}{5}\frac{(1-S_o)^2 f^2}{(A_E)^2} \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad \text{(B-1)}$$

or using Equation (A-10)

$$k = \frac{f}{5}\gamma^2\left[\int_1^{S_o} P_c\, dS\right]^2 (1-S_o)^2 \quad . \quad . \quad . \quad \text{(B-2)}$$

where f, S and S_o are fractional; P_c is expressed in dynes per sq cm, γ in dynes per cm, and k in sq cm.

The above relations imply that not all of the fluid filling a porous body participates in the flow, and that the fraction held immobile is approximately equal to the irreducible minimum saturation as indicated by capillary displacement experiments.* Equation (B-2) may be used to calculate the specific permeability from capillary pressure data.

Table I shows the comparison between calculated and measured dry air permeability for 27 samples which vary widely in permeability, porosity, and textural characteristics. It might be noted that in 21 cases the calculated permeability is smaller than that actually measured. Such a systematic trend may be explained by the fact that the measured dry air permeabilities have not been corrected for gas slippage effects.

It is seen that the average discrepancy between the measured and the calculated results is greater for the natural cores than for the artificial cores. It must, however, be indicated that the degree of precision of the experimental data on most of the natural core samples is not very high. The core material itself seemed to be extremely sensitive to chemical agents so as to be subject to definite changes (in surface and even textural characteristics) with time.

In the light of these remarks the overall agreement between calculated and measured values of permeability can be considered as satisfactory and may be interpreted as a good verification of the presented theoretical approach.

APPENDIX C
DERIVATION OF THE LIMITING K_L MAXIMUM

Under any circumstances, it can be considered that the gas inside the porous medium is flowing through a certain channel system surrounding clusters of rock grains containing liquid in their interstices. The assembly of all these clusters may be treated like an entirely water saturated "reduced" porous medium, the porosity of which would be equal to

$$\frac{Sf}{1-f+Sf}$$

so that under the assumption of isotropic random packing,

$$\frac{a_L}{a_s} = \frac{\text{total cross sectional liquid area}}{\text{total cross sectional solid area}} = \frac{Sf}{1-f} = \frac{\text{water volume}}{\text{rock volume}} \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad \text{(C-1)}$$

A schematic illustration is given in Fig. 14, where one pore opening between two rock grains is represented.

The total outside surface area of the "reduced" porous medium is equal to $A_G = I + R_G$. The following interpretation can then always be given to the ratio

$$\frac{I}{R_G}$$

namely,

$$\frac{I}{R_G} = \frac{\text{liquid surface exposed to gas}}{\text{solid surface exposed to gas}} \quad . \quad \text{(C-2)}$$

Under the previous assumption of isotropic packing, the inequality

$$\frac{I}{R_G} > \frac{a_L}{a_s} = \frac{Sf}{1-f} \quad . \quad . \quad . \quad . \quad . \quad \text{(C-3)}$$

can be established with help of the following reasoning. The liquid is the wetting phase so that it actually "spreads" over the rock, creating a total liquid-gas contact area, I, that is greater than the (average) cross sectional area, a_L of the pore space containing the water. As a consequence, the total solid surface that remains exposed to the gas, R_G, will be smaller than the (average) cross sectional area, a_s, of the solid grains so that one has simultaneously:

$$C.I = i > a_L \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad \text{(C-3}^a\text{)}$$

$$C.R_G = r < a_s \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad \text{(C-3}^b\text{)}$$

where i and r represent the projections of the curved surfaces I and R_G respectively on the considered cross-sectional plane. C is the factor of projection or shape factor of these surfaces, and is assumed to be the same for the rock grains and the interfaces. By combination of (C-3^a) and (C-3^b), inequality (C-3) is obtained. In fact, at low liquid saturations C is smaller for the interfaces than for the rock which still increases the resultant inequality (C-3).

The ratio

$$\frac{i}{a_L}$$

can be approximated in the following way: the surface i can

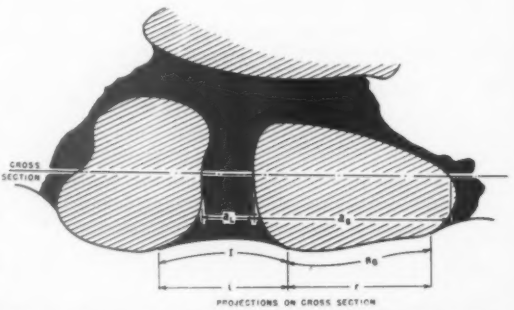


FIG. 14 — SCHEMATIC COMPARISON BETWEEN ROCK SURFACES AND INTERFACES.

*It has already been recognised by King,[15] and later by Kozeny,[16] as well as by other workers,[16,17] that in a single phase system some part of the fluid seems to be held back in internal angles and fissures, and in zones of grain contacts where molecular forces of adhesion become prevalent. Therefore, in the original Kozeny equation,[5] the porosity, f, should be assigned a slightly lower value, and the surface area, A, should actually correspond to some "effective flow matrix" and not to the specific solid surface.

be considered as corresponding to a mean hydraulic radius given by

$$h_i = \frac{2\gamma}{P_e} \quad \ldots\ldots\ldots \quad (C\text{-}4)$$

whereas the mean hydraulic radius of the pore space, *i.e.*, that corresponding to the cross sectional area, a_L can be shown to be given by

$$h_L = \frac{2\gamma}{P_m} \quad \ldots\ldots\ldots \quad (C\text{-}5)$$

where P_m represents the mean capillary pressure over the saturation range S to S_o, *i.e.*,

$$P_m = \frac{1}{S - S_o} \int_S^{S_o} P_c dS \quad \ldots\ldots \quad (C\text{-}6)$$

The ratio of the surfaces i and a_L can then be expressed as

$$\frac{i}{a_L} = \left(\frac{h_i}{h_L}\right)^2 = \left(\frac{P_m}{P_c}\right)^2 \quad \ldots \quad (C\text{-}7)$$

Combining Equation (C-7) with the relations (C-3), (C-3'), and (C-3'') gives

$$\frac{I}{R_G} > \frac{Sf}{1-f}\left(\frac{P_m}{P_c}\right)^2 \quad \ldots\ldots \quad (C\text{-}8)$$

from whence

$$I \text{ minimum} = R_G \cdot \frac{Sf}{1-f}\left(\frac{P_m}{P_c}\right)^2 \quad \ldots \quad (C\text{-}9)$$

The combination of (C-9) and the relation

$$A_G = I + R_G = -\frac{f}{\gamma}\int_1^S P_c ds \qquad \text{(See Appendix A, Equation A-8)}$$

yields

$$I \text{ Minimum} = A_G \cdot \frac{1}{1 + \frac{1-f}{Sf}\left(\frac{P_c}{P_m}\right)^2} \quad \ldots \quad (C\text{-}10)$$

Substitution of the above expression in the equation

$$A_L = -\frac{f}{\gamma}\int_S^{S_o} P_c dS + 2I \qquad \text{(See Appendix A, Equation A-12)}$$

gives

$$A_L \text{ Minimum} = -\frac{f}{\gamma}\left[\int_S^{S_o} P_c dS + \frac{2\int_1^S P_c dS}{1 + \frac{1-f}{Sf}\left(\frac{P_c}{P_m}\right)^2}\right] \quad \ldots\ldots \quad (C\text{-}11)$$

In accordance with Equations (11) of the Main Report and (A-10) of Appendix A, the final expression for the maximum of the relative permeability is then given by

$$K_L \text{ Maximum} = \frac{S^2\left[\int_1^{S_o} P_c dS\right]^2}{\left[\int_S^{S_o} P_c dS + \frac{2\int_1^S P_c dS}{1 + \frac{1-f}{Sf}\left(\frac{P_c}{P_m}\right)^2}\right]^2} \quad (C\text{-}12)$$

or using the symbols of the Main Report and Appendix A

$$K_L \text{ Maximum} = \frac{S^2\left[\Sigma_{S_o}\right]^2}{\left[\Sigma_S + \frac{2\Sigma_S}{1 + \frac{1-f}{Sf}\left(\frac{P_c}{P_m}\right)^2}\right]^2} \quad (C\text{-}13)$$

DISCUSSION

By Charles G. Dodd, U. S. Bureau of Mines, Bartlesville, Okla., Member AIME

The authors' work is a most stimulating contribution to the study of the complex problems involved in the flow of fluids through porous media. This reviewer has profited greatly from a study of the paper which undoubtedly represents the end product of much careful analysis. The following comments are presented in an effort to implement rather than detract from the value of the ideas presented.

Among the fundamental assumptions, stated and implied, upon which the paper is based are the following: (1) In single-phase fluid flow through a porous medium the fluid filling all minute crevices, cracks and pores is stagnant and does not participate in flow. (2) The total volume of stagnant liquid may be identified with the irreducible minimum liquid saturation measured by a capillary pressure experiment. (3) If a flowing liquid is under consideration, the volume of each pore which is filled with stagnant liquid is determined by the curvature of the liquid-gas interface, *i.e.*, by the solid geometry and the surface tension of the liquid. (4) There is no slippage at the boundary between flowing liquid and stagnant liquid. (5) In relative permeability to liquid measurements when the gas phase is immobile there is no slippage at the liquid-gas interfaces within the voids of the porous medium. (6) In analyzing the free energy change involved in the displacement of liquid from a porous medium by gas it is assumed that a solid-liquid interface is replaced by a solid surface covered by a liquid film having the surface tension of the bulk liquid or by a surface of equal energy. It would be profitable to discuss these assumptions in turn.

The Kozeny equation[1] has been applied by Carman[2,3,4] and others to determination of the specific surface areas of finely divided materials by measuring the fluid permeabilities of unconsolidated beds. The method has enjoyed wide acceptance in recent years, and the surface areas measured thereby agree well with area measurements made by independent methods, although it is recognized[5] that the internal areas of porous silica gels, etc., are not evaluated by the method. For permeability experiments to measure a solid surface area, the solid surface must offer a frictional resistance to flow, and the flowing fluid must everywhere contact the surface. In recent work at the Bureau of Mines laboratories[6] we have obtained agreement to better than three per cent between the specific surface areas of a sample of 70- to 100-mesh glass beads as calculated from liquid permeability experiments to water and isoöctane, and precise, independent miscroscopic measurements. These glass beads were of the average size of grains in many sandstone reservoir rocks. Packed beds of the beads probably would retain 10 to 15 per cent water at completion of a displacement experiment as an irreducible minimum water saturation, but no correction was made for this in our work such as the authors suggest in their Equation (B-1). On the basis of the above remarks, it is felt that assumptions (1) and (2) do not have general applicability to all porous systems. However, in the case of sandstone reservoir rock material, for example, the presence of cementing material, clay minerals, and very fine silt between coarser sand grains alters the picture. Undoubtedly the fluid in such fine crevices does not participate in flow.

In the case of assumption (3) it is difficult to understand how the curvature of a hypothetical liquid-gas interface can determine the boundary between flowing and stagnant liquid in a continuous liquid phase. It would seem more appropriate to attribute such a phenomenon to attraction of the solid for

the stagnant liquid, but no analysis of this situation has been developed. On the other hand the concept serves as a working hypothesis to stimulate further research.

Assumption (4) is a difficult one to accept, but it may sit better on further reflection. Assumption (5), on the other hand, seems to be untenable. It is involved in the authors' definition of A_L which is used throughout their development. This reviewer would suggest that the analysis be reconsidered on the basis of a more plausible definition of A_L, eliminating the gas-liquid interface as one where friction is involved.

In Appendix A the authors, apparently without realizing it, have made assumption (6), which seems a reasonable one to this reviewer if the saturating liquid wets the solid with a zero contact angle. The authors assume the work done in the displacement process is that necessary to form new liquid surface having an area A_G. It should be pointed out that this results in R_G always being zero, a condition the authors use in evaluating their minimum K_L function. However, if R_G is always zero, the ratio I/R_G used in evaluating the maximum K_L function loses its significance.

REFERENCES

1. Kozeny, J.: *Sitzber. Akad. Wiss. Wien, Math.-naturw. Klasse*, (1927) **136**, (Abt. IIa), 271.
2. Carman, P. C.: *Trans.* Inst. Chem. Engrs. (London, 1937), **15**, 150.
3. Carman, P. C.: *J. Soc. Chem. Ind.* (London), (1938), **57**, 225 T.
4. Carman, P. C.: *Ibid.*, (1939), **58**, 1.
5. Sullivan, R. R., and Hertel, K. L.: *Advances in Colloid Science*, I, 37-80, Interscience Publishers, Inc., New York, (1942).
6. Dodd, C. G., Davis, J. W., and Pidgeon, F. D.: *J. Phys. and Colloid Chem.*, in press.

AUTHOR'S REPLY TO MR. DODD

Dodd's very clear analysis of the assumptions used in the theoretical developments of this paper contributes toward the recognition of some fundamental aspects of fluid mechanics in porous media and represents a most valuable basis for constructive discussions. The authors want to take this opportunity for indicating that one of their main purposes has been to attempt the definition of a series of "working hypotheses" and to outline thereby a logical basis for further research.

With respect to assumption (5) the authors can hardly follow the views expressed by Dodd. It is not excluded that there may be some slippage at the liquid-gas interfaces. Accordingly, a more elaborate derivation could possibly be worked out, provided there were any tangible indication as to the exact amount of slippage to be accounted for. It can be anticipated that the consideration of slippage on part of the liquid boundaries would lead to a situation that is somewhat different from what is usually admitted, namely applicability of Darcy's law to each of the flowing phases. It is believed that in any event neither the principle of the theoretical treatment nor the nature of the boundaries would be altered. At this time, therefore, it does not appear that the definition of the liquid boundary A_L ought to be modified or even that the assumption of zero slippage at the liquid-gas interfaces is untenable.

It is felt that some confusion might arise in connection with the comments concerning asmption (6). As Dodd points out, there is actually no formation of true molecular contact between the gas and the solid surface since it is implied that the latter remains at all times covered by a liquid film. This film must be visualized merely as an immobile coating layer of infinitesimal thickness. With respect to the spatial distribution of fluids, it is necessary to distinguish between the interfacial area, I, separating the gas from the flowing bulk liquid, and the area of triple contact "gas/liquid - film/solid" which for reasons of simplicity has been termed "solid-gas" contact area, R_G. From the foregoing it is then clear that R_G must always be assigned a definite value and that it becomes zero only in the case of complete gas channeling such as may be seen from Figs. 1 and 4.

DISCUSSION

By M. R. J. Wyllie, Gulf Research and Development Co., Pittsburgh, Pa., Member AIME

The authors are to be congratulated on a most interesting and provocative paper which will, I am sure, give rise to much discussion. For this reason it is my intention to discuss here only those aspects of the authors' work which appear to be fundamentally at variance with certain published works of Rose and myself.[1,2] My hope is either to reconcile the differences or failing that, at least to underline them so that some later worker may be in a better position ultimately to resolve them.

Firstly, I am most happy to see that more work applying the Kozeny equation to consolidated porous media is now in print; nevertheless, I feel that a word of caution is in order since the application of the Kozeny equation to such media has not yet received wide support; indeed, Carman, one of the principal protagonists of the theory, has outlined at length the rather severe theoretical requirements which must be met before its use is justified.[3] Nevertheless, I agree that the validity of this equation when applied to consolidated porous media can only be tested by experiment and the authors data make further such tests possible.

Where I differ from the authors is (a) in the employment of the "effective porosity" concept in the type of porous media used by them and (b) in the magnitude of the Kozeny constant, t, applicable to consolidated porous media.

With regard to (a) I believe that this concept, as suggested by Kozeny,[4] Zunker[5] and Carman[4] for clays, is valid; I have found it useful myself[7] for the theoretical treatment of fluid flow through mud filter cakes. Nevertheless, clays are unique in that they undoubtedly absorb strongly an appreciable water film. Thus, the concept of the effective flow porosity of a clay particle system being less than the porosity determined solely by the amount of "interstitial" water present in the system is not unreasonable; indeed some such postulate is essential if the well-known fact is to be rationalized that the permeability of a clay particle system may be essentially zero when its porosity is appreciable. A similar concept may apply to all porous systems, as pointed out by the authors; here the discussion by Carman[3] quoting the results of King,[8] Erikson[10] and Darapsky,[11] all of whom tended to a view similar to that held by the authors, is relevant. Nevertheless, it is, I believe, important to note that all direct substantiations of the Kozeny equation, including those cited by the authors, involve the

use of the total surface areas and total porosities of the systems investigated; *i.e.*, in Equation (5) of the authors, k, f and A were directly measured and thus t found. It is, of course, possible that, by the use of appropriate effective porosities and surface areas, the same constants would have been found by the workers quoted in the authors' references;[4,5,6,7] nevertheless, this was not done and hence it does not appear wholly appropriate for the authors to cite these data as a justification of their choice of a Kozeny constant of 5.

It may be emphasized that, as noted by the authors, the Kozeny constant of 5 is experimentally proved to be only an approximate figure for flow through isotropic unconsolidated porous media. In non-isotropic unconsolidated porous media the constant varies with the direction of flow being, respectively, approximately 3 and 6, for flow parallel to and perpendicular to the long axes of a bed of fibers.[12] It is the view of Sullivan and Hertel[13] and of Rose and myself[2] that the Kozeny constant is a function of what has been called the tortuosity of the porous system through which flow occurs. In the case of the fiber bed quoted above the tortuosities are approximately 1 and 2 respectively and, if a reasonably constant shape factor of about 3 is assumed (Carman[4] adduces evidence for this), the directional Kozeny constants of 3 and 6 are obtained as the product of the tortuosity and shape factor. In consolidated porous media, Rose and I[2] have noted from electrical evidence that tortuosities much higher than those applicable to unconsolidated systems seem applicable, and hence we assume that Kozeny constants much exceeding 5 are applicable to such unconsolidated systems. We have adduced some experimental evidence to support this contention. In addition we have noted[2] that tortuosity appears to vary with saturation in all porous media and give as the relationship between T, the tortuosity at 100 per cent saturation, and T_s, the tortuosity at some saturation, S, of wetting phase, the relationship,

$$T_s/T = S^2I^2$$

where I is the electrical resistivity index pertaining to the saturation, S. It may be noted that a variation of tortuosity with saturation has recently been suggested also by Fatt and Dykstra.[12]

It is important then to point out that Rapoport and Leas use a constant of 5 for consolidated porous media and specifically state that to a good approximation they believe there is no variation of the constant with saturation. Hence their position is quite different from that of Rose and myself and clearly the divergence in outlook can only be settled by reference to the experimental facts. Table I in the authors' paper gives experimental results which the authors cite as a general confirmation of their theoretical reasoning. They note that although the agreement between measured and computed permeabilities is not precise, there are considerable experimental difficulties attached to work of the kind carried out and thus the over-all average agreement of ±12 per cent between computed and measured permeabilities supports the validity of the Kozeny constant of 5 which they employed in all cases. Certainly I do not question the experimental difficulties involved in compiling Table I and the overall agreement noted must, therefore, be considered as rather good support of the

Table I—Comparison Between Calculated and Measured Specific Permeabilities

NATURAL CORES						ARTIFICIAL CORES					
Formation	Designation	f%	K_M in md	K_C in md	$\frac{K_C - K_M}{K_M}$ in %	Core Material	Designation	f%	K_M in md	K_C in md	$\frac{K_C - K_M}{K_M}$ in %
Third Deese Sand	B14	9.3	15.7	30.0	+90.0						
Third Deese Sand	B 3	15.4	17.0	24.5	+44.0						
Bartlesville Sand		21.2	25.0	22.8	− 8.8						
Third Deese Sand	B13	11.3	26.0	39.5	+29.0	Alundum	C1	21.8	30.8	28.8	− 6.5
Third Deese Sand	B10	14.2	117.0	86.5	−26.6	Alundum	C2	24.2	72.2	55.3	−27.0
Third Deese Sand	B25	13.6	127.5	104.0	−18.5						
Third Deese Sand	B 5	16.3	133.0	103.0	−22.5						
Third Deese Sand	B37	15.8	139.0	108.0	−22.0						
Third Deese Sand	B27	14.8	154.0	112.5	−27.0						
Third Deese Sand	B33	16.2	159.0	131.0	−17.5						
Third Deese Sand	B19	12.6	174.5	149.0	−14.5	Alundum	C3	24.5	177.0	144.0	−18.6
Third Deese Sand	B55	15.3	182.5	199.0	+ 9.0						
Third Deese Sand	B41	16.6	213.0	150.0	−29.5						
Third Deese Sand	B 1	17.0	226.0	158.0	−32.0	Alundum	1186/35/2	23.4	220.0	198.5	−10.0
Third Deese Sand	B48	17.3	243.0	192.0	−21.0						
Third Deese Sand	B 8	16.8	301.0	244.0	−18.6						
Third Deese Sand	B 4	17.8	470.0	271.0	−42.5	Alundum	C4	27.4	567.0	566.0	0.0
Nichols Buff Sand		21.5	660.0	590.0	−10.6	Alundum	C5	30.0	1,385.0	982.0	−28.8
Bromide Sand		18.3	2,543.0	2,710.0	+ 6.6	Penn State		33.2	2,710.0	2,700.0	− 0.03
Unconsolidated Sand		35.0	17,200.0	12,000.0	−30.0						

Average Error on Natural Cores: 26.0 Per Cent

Average Error on Artificial Cores: 13.1 Per Cent

Average Error: 22.6 Per Cent

f% = Porosity
K_M = Measured Permeability in md
K_C = Calculated Permeability in md
$\frac{K_C - K_M}{K_M}$ = Error in Per Cent

authors' contentions; alternatively the data may be indicative of the fact that there are at least two plausible methods of skinning this particular cat.

The computed permeabilities in Table I are derived essentially from the relationship:

$$k = \frac{1}{5}\,\frac{(1-S_w)^2\,f}{A^2_K} \qquad \ldots\ldots\ldots\ldots \quad (1)$$

whereas, Rose and myself have suggested:[2]

$$k = \frac{1}{t}\,\frac{f}{A^2} \qquad \ldots\ldots\ldots\ldots \quad (2)$$

with $t > 5$ in all cases. (Actually $t = F^2 f t_s$, where F = formation factor and t_s = shape factor and is approximately = 2.5 – 3.0.)

Now in all cases $(1-S_w)^2 f < f$ and it seems probable that $A_K < A$. (It seems pertinent to note that the use by the authors of $-f/\gamma \int_1^{S_w} P_c\,dS = A_K$ is not wholly in accordance with the recommendations of Leverett in Reference[9] of the authors.) Depending upon the relative values of $(1-S_w)^2 f$, A_K^2 and t it would appear that both Equations (1) and (2) above could give approximately correct values of k. At this stage I do not believe it possible to decide which of the two equations is the more fundamental.

REFERENCES

1. Wyllie, M. R. J., and Rose, W. D.: *Trans.* AIME, (1950) **189**, 105.
2. Wyllie, M. R. J., and Rose, W. D.: *Nature* (Lond.) (1950) **165**, 972.
3. Carman, P. C.: *Discussions of the Faraday Soc.*, (1948) No. 3, 72.
4. Kozeny, J.: *Kultur techniker* (1932) **35**, 478.
5. Zunker, F.: *Z. Pfl Ernähr. Düng.*, (1932) **A25**, 1.
6. Carman, P. C.: *J. of Agri. Sci.*, (1939) **29**, 262.
7. Wyllie, M. R. J.: *Trans.* AIME, (1951) **192**, 1.
8. Carman, P. C.: *Trans. Inst. Chem. Eng.*, (Lond.) (1937) **15**, 150.
9. King: *19th Annual Rept.*, U.S.G.S., (1897-8), **2**, 59.
10. Erikson, S.: *J. Gasbeleucht*, (1920) **63**, 615.
11. Darapsky: *Z. Math. Phys.* (1912) **60**, 170.
12. Sullivan, R. R., and Hertel, K. L.: *Advances in Colloid Science*, Interscience Publishers, (1942).
13. Fatt, I., and Dykstra, H.: "Relative Permeability Studies," presented at AIME Fall Meeting, (1950), Los Angeles, Calif.

AUTHOR'S REPLY TO MR. WYLLIE

The authors fully appreciate the importance of Wyllie's comments. They feel, however, that a sufficiently detailed answer would require considerable divergence from the issue at hand. In the near future it is planned that a note containing additional experimental data will be written concerning the significance of the textural constant.

DISCUSSION

By J. S. Osoba, Humble Oil and Refining Co., Houston, Tex.

The authors have presented a useful method of calculating relative permeability to the wetting phase under drainage conditions when the capillary pressure versus saturation relations are known for reservoir rock. The agreement between calculated and experimental relative permeabilities is proof of the validity of the calculated method provided the experimental method is free of errors.

Several methods of measuring relative permeability have been investigated in our labortory. The relative permeability to the wetting phase measured by three of these methods, the Penn State, single core dynamic, and gas drive technique, were nearly identical to the curves calculated from the capillary pressure curves using Rapoport and Leas' equation for $K_L(\min)$. One method, the Hassler method, which is most nearly like the method used by Rapoport and Leas, gave a relative permeability to the wetting phase that was lower than the calculated curve, using the equation for $K_L(\min)$.

Since there are laboratory methods whereby the relative permeability to the wetting phase can be measured and the results coincide with the calculated relative permeability to the wetting phase, and since these methods are many times faster and less difficult to operate than the method presented in this paper, I do not believe the authors are justified in concluding that their method of calculating relative permeability is superior to experimental methods.

With reference to another point in the paper, in calculating specific permeability by the Kozeny equation [Equation (6)], the result is very sensitive to the value chosen for the irreducible minimum saturation on the capillary pressure curve. This is due to the fact that the irreducible minimum saturation determines the factor A [in Equation (6)], and a small variation in this irreducible minimum causes a large change in A. Since this factor appears in the equation as A^2, the accurate determination of this factor is very important. It would be of some help in evaluating the data presented in Table I if the procedure used to determine the factor A were explained.

AUTHOR'S REPLY TO MR. OSOBA

Osoba's statement concerning the agreement that he found between the calculated curves and direct measurements of liquid relative permeability is most gratifying and provides a further substantiation of the theory advanced by the authors.

It is readily admitted that there is a certain resemblance between the Hassler method and the experimental technique presented in this paper insofar as both require the use of semipermeable capillary barriers. It may, however, be stated that the results obtained by the Hassler method are subject to a systematic error due to the distortion of the flow pattern from linear whereas the procedure used by the authors has been conceived so as to eliminate any such anomalies.

As regards the superiority, from the viewpoints of cost and time, of experimental methods over that of calculating, the latter has been recommended merely in preference to that experimental method which is presented in this paper. The authors certainly do not deny the possibility of more economical methods. They would, on the contrary, advocate the use of more advantageous methods, as soon as their reliability and economy could be sufficiently demonstrated. ★ ★ ★

The Drift of Things

. . . as followed by **EDWARD H. ROBIE**
Secretary AIME

The pressing duties of arranging a successful AIME Annual Meeting in St. Louis, Mo., last month prohibited Robie's writing his column for this issue. With apologies to the patrons of this page, Jess E. Adkins, editor of the JOURNAL OF PETROLEUM TECHNOLOGY, *is substituting for Robie.*

Annual Meeting

The nearly 2,500 members who attended the Annual Meeting last month in St. Louis came away from that city with the feeling that those who did not attend missed a good thing. The 171st General Meeting of the AIME was indeed a success. The amount of effort expended in preparing some 400 papers for presentation is immeasurable, but evident in the manner in which technical sessions of all divisions and branches were attended.

Dr. Donald H. McLaughlin, immediate past-president of the Institute, was moved to remark at the Welcoming Luncheon that the last time the AIME met in general session in St. Louis was in 1884. The records of that meeting are not at hand, but it is wondered if the city in those days could have handled as gracefully the many simultaneous meetings which took place in 1951. No less than four hotels were involved in this most recent gathering. The Jefferson Hotel was almost taken over by the Institute while the Statler Hotel was predominantly occupied by the Petroleum and Metals branches.

The ten petroleum papers and the production review session were all well received, evoking considerable discussion from the floor. Several of the papers will become a part of the *Transactions* while a summary of domestic production for 1950 is carried elsewhere in this issue of PETROLEUM TECHNOLOGY. A similar summary of foreign production for 1950 will appear in the April issue.

At the Welcoming Luncheon, the Institute heard the eminent physicist, Arthur Holly Compton, chancellor of Washington University, warn the world against another earth-wide conflagration. He expressed his belief, though not in an optimistic tone, that by the very nature of the destructiveness of the atomic bomb (and subsequent developments along the same lines) such a catastrophe would be avoided at least for a time. He also defended, from the physicist's standpoint, the development of such a destructive force. The role of the scientist is not, Dr. Compton pointed out, to bestow happiness upon a people; rather it is to bestow greatness.

Texas Railroad Commissioner William J. Murray made an urgent plea for the submission of accurate reserve estimates by petroleum engineers. As guest speaker at the Petroleum Branch banquet, Murray was concerned about the apparent chasm between the painted picture of petroleum reserves and production possibilities and the actual picture. He reported that allowables have jumped in recent months due to military needs but that "pre-Korea" estimates of production capacities have fallen short of their claims. He posed these questions: What amounts should import volume reach? What allowables should be set? To what extent should we depend upon Middle East production? The answers, Murray observed, could be found only through the scrutiny of more accurate engineering reports of estimated reserves.

W. M. Peirce, AIME president, attended the Petroleum Branch banquet and urged that the Institute's goal for 1951 be a substantial increase in membership.

Random Notes

There was no deficiency of "favors" at the various functions in St. Louis. At the Welcoming Luncheon members were given palladium tie clips while the ladies received ear clips of the same metal. At the Dinner-Smoker, clothes brushes of aluminum (except for the bristles) were donated and leather bound desk sets were given out at the Annual Banquet . . . The banquet offered a sight seldom seen anywhere except in the United States. Tickets were marked with the words "Dress — optional." As it turned out, the manner in which a man was dressed could almost be matched with his table location in the room. White ties were popular at the speakers' dais while the front-center section was dotted with dinner jackets. Those in the rear were probably the most comfortable of all in conservative street clothes. The ladies, of course, were formal to a man, as it were. . . No such problems of choice existed at the Petroleum Branch Banquet which was informal.

Technical sessions of the Branch were all held in the St. Louis Room of the Statler Hotel. An overflow crowd was the rule but no one turned away because of a lack of seating facilities. . . They merely chose a good location on the floor and listened Indian style. . . A word of appreciation should be extended the projectionist on duty during the petroleum sessions. He knew what he was doing every minute. . . The Statler lived up to its advertising. Courtesy was the rule, and service (in preparation of meetings) was carried out unobtrusively. A microphone was provided on five minutes notice which is a record of some sort. . . The Dinner-Smoker might also have established a record. Five male voices stole the show. . . . The maturity of St. Louis was evident everywhere. Some, who might view business district traffic signals as a necessity, might even think it quaint. Traffic policemen seemed to have things under control at all times, however. At least, no pedestrians were run down during the four-day meeting.

American ingenuity was manifested in the acts of some members who waited until the last minute before flying to the meeting. Weather conditions throughout the Midwest had planes on the ground over the week end of Feb. 17-18. Stranded in Springfield, Mo., Bob Gilmore of DeGolyer and MacNaughton rallied several plane loads of folks and chartered an earthbound bus. They all arrived in St. Louis heavy-eyed but present at 4 a.m. . . Bob had a Petroleum Branch treasurer's report to make.

All St. Louis cabs bore "Welcome AIME" signs on windows. . . So did some of the bars. . . The AIME Section Delegates report to the Board of Directors received many compliments for constructiveness. Some action was taken on all counts. . . Alaska has a new local section. . . Economy was the keynote at the Board meeting. Measures requiring expenditures received heavy consideration. ★ ★ ★

THE SECOND NATIONAL BANK OF HOUSTON

Oil and Gas Division

WE SALUTE the outstanding contribution to the science of petroleum production and development made by the "AIMME" and its Journal of Petroleum Technology.

We take pleasure in announcing a schedule of advertising in this publication.

44 Years of Service to the Southwest

The SECOND NATIONAL BANK OF HOUSTON
MAIN AT RUSK

CAPITAL AND SURPLUS TEN MILLION DOLLARS . . . MEMBER F.D.I.C.

Table I — Recovery Tests of Winkler County Storage System

Test No.	LPG Injected Gal	LPG Recovered Gal	LPG Loss Gal	LPG Recovered %	Vapor psi @ 105°F In	Vapor psi @ 105°F Out	Corrosion Test In	Corrosion Test Out	Cobalt Test In	Cobalt Test Out	IBH In	IBH Out	Doctor In	Doctor Out
1	63,452	60,867	2585	95.9	205	225	No	No	Dry	Trace	–56	–56	OK	OK
2	62,997	62,801	196	99.7	205	225	No	No	Dry	Trace	–56	–56	OK	OK
3	13,487	13,416	71	99.5	221	225	No	No	Dry	Trace	–56	–56	OK	OK
4	13,075	12,951	124	99.1	225	230	No	No	Dry	Trace	–56	–56	OK	OK

LPG Storage Cavities

Continued from Page 11, Section 1

example, a second string of tubing with a bottom hole pump may be employed to remove salt water from the reservoir as LPG is injected into the annular space, thus avoiding excessive pressures on such formations. Fig. 4 shows the necessary formation depth to permit a desired surface pressure with propane storage.

Also in formations that will not support excessive gradients, LPG may be injected through the tubing under gas at sufficient pressure to maintain the desired surface pressure. Storage in contact with gas, however, will alter the vapor pressure of the stored product which may be objectional in some cases.

TESTING

The Upton County project has been tested only once. On this test, 1,500 bbl of propane were injected, of which approximately 96 per cent was recovered. This was deemed adequate proof by the operator of the feasibility of the method, and the reservoir was placed in commercial service. Enlargement of the Winkler County storage system was shut down at approximately 8,000 bbl capacity and four tests were conducted to determine the practicality of the method, and to allow public demonstrations of the process. The results of testing are shown in Table I.

In all tests LPG was injected and withdrawn at a rate of approximately 300 bbl per hour, the limiting factor apparently being only the size of the tubing. The effluent LPG was found to have increased in vapor pressure, which is believed to be primarily due to absorption of residue gas used over the LPG in the surface tanks to increase the pressure on the suction end of the injection pump. Also, cobalt bromide tests on the recovered LPG indicated a very slight trace of moisture. The primary question to be answered by this testing was what proportion of injected products could be recovered. It is believed that the moisture content resulted from the withdrawal of all recoverable products in each test, and that under normal operation, withdrawn products probably will be dry.

APPLICABILITY

To date, no attempts have been made to apply this principle to formations other than salt, but as many shales readily disintegrate in water, it is believed that in many localities, shale beds exist suitable to the process. Also in some cases it may be feasible to dissolve space out of massive limestone with hydrochloric acid.

Effort is being made to locate all salt deposits suitable to the process, but the study is by no means complete. The Permian salt of West Texas extends over into Eastern New Mexico, up through West Central Oklahoma and Central Kansas almost to the Nebraska line. A sizable deposit exists in Western Colorado and Eastern Utah and some small deposits are in Southern California. Also extensive salt beds underlie most of Michigan and extend into Eastern Ohio, Northern West Virginia, Western and North Central Pennsylvania, and Southwest New York. The salt domes of the Gulf Coast are believed applicable to the process.

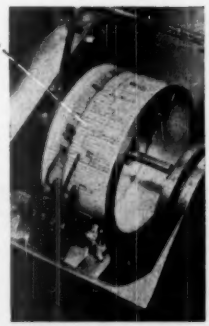
In consideration of the probable, though untried, applicability to shales and lime stones and proven economy of the system in salt beds, it is believed the formation of underground storage space by artificial means will alleviate a considerable portion of the LPG storage problem.

ACKNOWLEDGMENT

The writer wishes to express his appreciation to G. H. Billue of Hydrocarbon Storage, Inc., for his cooperation in the preparation of this paper. ★ ★ ★

SEE formation changes *as you drill* WITH GEOLOGRAPH

With Geograph, you actually watch the drilling change as the bit bites into contrasting strata — foot by foot! You'll find that this subsurface control, while drilling, results in a higher percentage of successful drill stem tests; fewer and more correctly placed cores; accurate determination of net pay thickness and elimination of many depth corrections!



Houston, Odessa & Wichita Falls, Tex. • Casper, Wyo. • Shreveport & Baton Rouge, La. • Bakersfield, Calif.

TIME WILL TELL

THE GEOLOGRAPH CO. INC.

P. O. Box 1291 Oklahoma City 1, Okla.

Personals

W. T. NIGHTINGALE of Rock Springs, Wyo., has been elected president of the Mountain Fuel Supply Co. of Salt Lake City, Utah. He has formerly been with Whitehall Petroleum Corp., Ltd., the New York Oil Co., and the Ohio Oil Co. In 1929, he was made chief geologist for Mountain Fuel Supply and in 1941 he became a vice-president. In 1945, he was made vice-president in charge of exploration, production and transmission. He will move soon to Salt Lake City from Rock Springs, Wyo.

+

FRANK LINDEMAN, JR., has been named general superintendent of the producing department of Stanolind Oil and Gas Co. in Tulsa, Okla. Prior to his present position, he was in charge of Stanolind's marine operations in the Gulf of Mexico.

+

WILLIAM B. BLEAKLEY is now with the University of Tulsa as assistant professor in petroleum engineering. He was formerly with Stanolind Oil and Gas Co., Alvin, Tex.

+

J. A. CRICHTON is now vice-president in charge of operations for the San Juan Oil Co. with headquarters in Dallas, Tex. He was formerly associated with the firm of DeGolyer and MacNaughton, Dallas, as vice-president and director. With the San Juan Oil Co., he will be in charge of the company's operations in leasing, drilling, development and production. Presently, he is chairman of the North Texas Section of the Petroleum Branch, AIME.

WILLIAM E. BERNHARD resigned from the Seaboard Oil Co. of Delaware, Casper, Wyo.

+

ORMAN PEARSON BROWN resigned from the Shell Oil Co., Denver, Colo., after nine and one-half years as geologist in the Midcontinent and Rocky Mountain areas. He has accepted a position with the Wilshire Oil Co., Inc., Los Angeles, Calif., to open Rocky Mountain Division offices in Denver.

+

RICHARD C. HARRIS is now resident manager, Venezuelan Atlantic Refining Co., Caracas, Venezuela. He was formerly located in Philadelphia for the same firm.

+

ALBERT LAZAR has accepted a position with the Michigan Consolidated Gas Co., Dearborn, Mich.

+

GEORGE L. LOCKETT, Mene Grande Oil Co., has been transferred from Caracas, Venezuela, to Maracaibo.

+

JOHN CURTIS MCCARTHY has been transferred from the Tulsa office of the Stanolind Oil and Gas Co. to the West Texas district office in Midland.

+

GLENN STALEY is now connected with the New Mexico Oil Co., Hobbs, N. Mex.

+

REX W. WOODS has resigned his position as chief reservoir engineer with the Creole Petroleum Corp., Caracas, Venezuela, and plans to open a consulting office in Tulsa, Okla., specializing in reservoir engineering, reserve estimation and evaluation.

MARSHALL L. STIRLING, formerly located in Dowell Incorporated's Tulsa, Okla., office, has been made head of the firm's Fort Worth, Tex., office. He has been with Dowell since June, 1939. He will act as sales manager in the Fort Worth office. Prior to his employment at Dowell, Stirling was sales manager with the Gas Lift Corp. of Houston, Tex.

+

IRA J. MEADOR is production foreman for the Skelly Oil Co., Tulsa, Okla.

+

R. B. SALE is now with the Seaboard Oil Co. of Delaware, Corpus Christi, Tex.

+

OWEN F. THORNTON is now associated with The Louisiana Land and Exploration Co. and will be in charge of the Petroleum Engineering Department. For the past seven years Thornton has been with The Texas Co. as senior petroleum engineer where he was concerned with reservoir studies, valuations and other engineering problems throughout the United States, Canada and South America. He was employed by The Tide Water Associated Oil Co. in the East Texas area after graduation and until 1944.

+

WILLIAM E. STILES has resigned as director of sales for Core Laboratories, Inc., to become associated with Ken Corp., Long Beach, Calif. Stiles, with headquarters in Dallas, will manage the manufacturing and sales of "Ken-Oil" oil-base drilling fluid outside of California.

Proposed for Membership, Petroleum Branch

Total AIME membership on December 31, 1950, was 17,082; in addition, 4,534 Student Associates were enrolled.

ADMISSIONS COMMITTEE

A. J. Phillips, Chairman; George B. Carless, John T. Sherman, Lloyd C. Gibson, R. D. Mollison, Plato Malozemoff, Ivan Given. Alternates, H. P. Croft, F. W. Hanson, T. D. Jones, Frank A. Ayer, H. W. Hitzrot, H. K. Masters.

Institute members are urged to review this list as soon as the issue is received and immediately to wire the Secretary's office, night message collect, if objection is offered to the admission of any applicant. Details of the objection should follow by air mail. The Institute desires to extend its privileges but does not desire to admit persons unless they are qualified.

In the following list C/S means change of status; R, reinstatement; M, member; J, Junior Member; AM, Associate Member; S, Student Associate; F, Junior Foreign Affiliate.

CALIFORNIA

Bakersfield — Dietzel, Norman E. (J) (C/S-S-J).
Costa Mesa — La Bouff, John J., Jr. (J) (C/S-S-J).
Los Angeles — Hamann, Paul M. (J) (C/S-S-J).
San Gabriel — Christensen, Robert D. (J) (C/S-S-J); Griffin, Will C., Jr. (J) (C/S-S-J).
Ventura — Bolstad, John H. (M) (R,C/S-J-M); Johnson, Bernard R. (J) (C/S-S-J).

ILLINOIS

Mattoon — Hammond, Ralph E. (M).
Olney — Loveless, Ernest T., Jr. (J) (C/S-S-J).

KANSAS

Bunker Hill — Cassell, Robert F. (A) (C/S-S-A).
Eureka — English, Homer C. (J) (C/S-S-J).
Kantoul — Bossler, David P. (J) (C/S-S-J).
Wichita — Patrick, Roy E. (M).

KENTUCKY

Prestonsburg — Huzzey, Thomas Edwin (J) (C/S-S-J).

LOUISIANA

New Orleans — Peterson, Albert F., Jr. (J) (C/S-S-J); Pyeatt, Woodrow W. (M) (R,C/S-S-M).

MISSISSIPPI

Laurel — Smith, Francis H. (A).

MISSOURI

Brentwood — Remmert, William (J) (C/S-S-J).

OKLAHOMA

Bartlesville — Dodd, Charles G. (M).
Bethany — Locker, George R. (J) (C/S-S-J).
Edmond — Flesher, Cranston W. (J) (C/S-S-J).
Healdton — Goad, Wilmer E. (J) (C/S-S-J).
Oklahoma City — Johnson, Grady E. (M).
Tulsa — Brainerd, Harold W., Jr. (J); Riggins, William H. (M); Shaw, George R. (J) (C/S-S-J).

TEXAS

Addicks — Gibson, Robert M. (J) (C/S-S-J).
Beaumont — Junod, William B. (M) (R,C/S-S-M).
Beliaire — Johnston, William R. (J) (R, C/S-S-J).
Big Spring — Miller, Robert N. (J) (C/S-S-J).
Borger — Nease, Charley W. (J) (C/S-S-J).
Brownfield — Rodelander, Clovis E. (J) (C/S-S-J).
Corpus Christi — Armstrong, John N., Jr. (J); Bramlet, Charles L. (M); Dornell, Grant S. (J).
Dallas — Hudson, Eddie J. (J); Stuart, Stanley H. (J).
Houston — Simmons, James M. (J); Thornton, Owen F. (M).
Kauntze — Jackson, James J. (J) (C/S-S-J).
Levelland — King, Glenn W. (J) (C/S-S-J).
Midland — Moore, Joe L. (M) (C/S-J-M).
Palacios — Smith, William P. (J) (C/S-S-J).
Premont — Turner, Willie J. (M) (R,C/S-S-M).
Randolph Field — Kozik, Eugene (J) (C/S-S-J).

VIRGINIA

Arlington — White, Foster L. (M) (C/S-A-M).

WEST VIRGINIA

Charleston — Detamore, Waber A. (J).

WYOMING

Casper — Churchwell, Robert M. (M) (C/S-J-M); Korn, Norman (J) (C/S-S-J).

ALASKA

Juneau — Glover, Norman J. (J) (C/S-S-J).

CANADA

Alberta — Glenn, William D. (M) (C/S-J-M).

VENEZUELA

Barcelona — Siegele, Harold L. (J).
Caracas — Hall, Merle Leroy, Jr. (M) (C/S-J-M). ★ ★ ★

Employment Notices

The JOURNAL will post notices of men and jobs available. Companies and AIME members are invited to use this space, for which there is no charge. Except as noted below, address replies to: Code (appropriate number), JOURNAL OF PETROLEUM TECHNOLOGY, 601 Continental Bldg., Dallas 1. Show return address on envelope. These replies will be forwarded unopened and no fees are involved.

Replies to the positions coded Y4735, Y4658(a), Y4658(b) and Y5642 below should be addressed to: Engineering Societies Personnel Service, 8 West 40th St., New York 18, N. Y. The ESPS, on whose behalf these notices are published here, collects a fee from applicants actually placed.

PERSONNEL

♦ February graduate, 26, married, wishes position related to geology. Has MS in geology and is available immediately for employment. Salary required, $325. A veteran of World War II and a Lieutenant (jg) in USNR. Code 142.

POSITIONS

♦ Petroleum engineer with at least five years' experience and capable of testing and completing wells to 12,000-ft depth. Also should be able to handle entire course of production. Headquarters Dallas, Tex. Independent producer employer. Salary open. Code 528.

♦ Engineers. (a) Petroleum Engineer Trainee (CNY-1279-W), 21-24, B.S. in petroleum or mechanical engineering. No experience required, but summer work in oil fields preferred. Will perform general field and office petroleum engineering work including bottom-hole pressures, checking well depths, performing routine analysis work in the laboratory, checking and posting pool maps, gas oil ratios, etc. Single status. Salary, $5,700 a year. (b) Petroleum Engineer Trainee (CNY-1280-W), 21-24, B.S. in petroleum engineering, preferably with some experience in petroleum industry. Will be required to learn Spanish. Will be trained to obtain a general knowledge of the industry, and obtain a good idea of a petroleum or chemical engineer's job. Salary if single, $5,700 a year; if married, $6,600 a year. Single status for six months. Location, Venezuela. Y4735.

♦ Instrumentation engineer, graduate chemical, with a minimum of eight to ten years' experience in chemical or oil refinery work. Must know electric and pneumatic instrumentation. Salary, $6,000-$7,200 a year. Y4658(a).

♦ Buyer with experience in purchasing materials for the chemical industry from large petroleum refiners. Salary, $4,800-$6,500 a year. Location, New York, N. Y. Y4658(b).

♦ Engineers. (a) Chief Reservoir Engineer, 25-40, with degree in engineering and about five to eight years' experience in petroleum engineering. Location, Peru. (b) Senior Petroleum Engineer, 25-40, with degree in petroleum engineering or equivalent, and about four to eight years' experience in reservoir engineering. Location, Peru. (c) Petroleum Engineering Laboratory Analyst, 25-40, with an engineering degree. Location, Colombia. Wellsite Mud Engineer, 25-35, with three to five years' experience. Location, Colombia. Y4642.

♦ Petroleum reservoir engineer with four years' experience to work on Tulsa engineering staff large independent. Supply usual application data including salary. Replies will be confidential. P. O. Box 2039, Tulsa. ★ ★ ★

Rock Bit Design

Continued from Page 21, Section 1

footage. Several tables were shown to indicate that rate of penetration is not always desirable, especially in very deep holes where round trip time is considerable. A cross section of the jet-type rock bit was shown. Because of the extreme mud velocity in bits of this type, the nozzles must be well streamlined and made of special abrasive resistant materials.

E.S.L.
BIBLIOGRAPHIES

No. 1. Filing Systems for Engineering Offices. 41 references. 1948. $2.00.

No. 2. Prestressed Reinforced Concrete. 190 references. 1948. $4.00.

No. 3. Precision Investment Casting by the Lost Wax Process. 111 references. 1949. $2.50.

No. 4. Pallets Used in Modern Materials Handling. 114 references. 1949. $2.00.

No. 5. Machinery Foundations; Design, Construction, Vibration Elimination. 120 references. 1950. $2.00.

No. 6. Non-Metallic Bearings. 101 references. 1950. $2.00.

No. 7. Domestic and Industrial Applications of Solar Heating. 149 references. 1950. $2.00.

No. 8. Management of Construction Jobs. 53 references. 1950. $2.00.

■

LIBRARY SERVICES AVAILABLE
LITERATURE SEARCHING
TRANSLATING
PHOTOPRINT AND MICROFILM COPYING

•

Ask for Descriptive Folder
Engineering Societies Library
29 West 39th Street, New York 18, N. Y.

Memorial

An appreciation by D. R. McKeithan and W. A. Schaeffer, Jr.

Alvin D. Whitman (Member 1924) died of a heart attack on January 3, 1951, in Denison, Tex. He was born in 1892, in Pulaski, Va., but his earlier years were spent in Iola, Kans., and Bartlesville, Okla. When 16 and for the next four years he worked with his uncle, the late T. J. Jones, well known mining and metallurgical engineer, and was engaged in diamond drilling and other activity in various western states and in Alaska and South America.

Returning to Oklahoma in 1912, he became a tool dresser and cable tool driller, and in 1915 went to Burma as drilling superintendent for Nathsingh Oil Co. He served in France for two years as first lieutenant in the Corps of Engineers during World I, and before returning home married Miss Carolyn Kingston, of Manchester, England. During the period 1920-29 he was drilling superintendent for Twin States Oil Co. and was with Shell as superintendent in West Texas 1929-31. With discovery of the East Texas Field in 1931, he entered the drilling contracting business, in which he remained as contractor and independent operator until his death. His headquarters and home had been in Houston, Tex., since 1934. During World War II, he again served in the Corps of Engineers, this time as a major.

Well read, a keen student, and possessed of broad engineering and mechanical ingenuity, he could claim a share in the development of many improvements in drilling and producing equipment and methods. ★ ★ ★

Meetings of Interest

Donald L. Katz will present a series of lectures on Natural Gas Engineering at the University of Kansas, March 26-27. Advance registrations should be sent to E. A. McFarland, Mgr., Lawrence Center, University of Kansas, Lawrence, Kansas. The enrollment fee is $7.50. Accommodations are available in fraternity houses at $2.50 up and at local hotels from $3.00 up.

Letters...
to the editor

To the editor:

Now that criticism is being asked for with respect to our publication, I will give you the opinion of an ordinary AIME member.

Part of the available material for publication seems to consist of papers previously given in large meetings. Naturally these will be old stuff to some but this, *per se*, should not be the sole objection. The main objection to some papers applies . . . to their being given originally.

For instance, there have been those that were by rights suitable for organizations of high class physicists or members of the Faraday Society. Not one per cent of our membership could follow or understand them. The summary . . . of these papers may be of benefit and can be understood. I am not belittling the fine work of these extraordinary men but do believe that papers could be given . . . without vast amounts of Greek letter formulae that are impressive but sleep-producing when not understood. Anything worthwhile can be expressed so that the organization as a whole can assimilate and make use of it . . .

Neither am I saying that a talk should be limited to high school mathematics. There is a happy medium, however, and very few members have continued their mathematical studies since leaving school; hence, while they appreciate the work and its necessity, the actual feeling is relief when the paper is over.

We have too much data on oil and gas developments in the various areas. A journal should pertain more to what occurs in (its) own organization, with selected papers that may be by non-members, which will fit the picture. Irving Fatt has some excellent suggestion in the final paragraph of his letter (PETROLEUM TECHNOLOGY, Dec., 1950). But papers on the subjects he suggests should be presented in a manner that will not be overpowering and only read by a minority group.

I am not trying to reduce our organization to a lower plane in making these suggestions. We can have erudite papers but the manner and form should be changed. A lecture does not have to be in Latin to have class . . .

C. E. Clason
Halliburton Oil Well Cementing Co.
Duncan, Okla.

Technical Note 67

Continued from Page 17, Section 1

the conversion factors do not depend significantly on the concentration, the 0.5 factor for the $SO_4^=$ is actually the mean determined for three solutions of Na_2SO_4, using $SO_4^=$ concentrations of 676 ppm, 2,030 ppm, and 3,030 ppm. The resistivity conversion factors found for these quantities of $SO_4^=$ were 0.553, 0.532, and 0.412 respectively. It is therefore recommended that a factor of 0.5 for $SO_4^=$ be used for the majority of oil field brine samples, in which the $SO_4^=$ concentration is relatively small compared to the $Cl-$ concentration. However, in some regions, such as the Rocky Mountains, the $SO_4^=$ concentration is large enough to be relatively important, and in these areas the factor corresponding to the existing $SO_4^=$ concentration should be used.

In order to check the accuracy of this method of calculating formation water resistivities, the resistivities of formation waters from 26 wells in the Gulf Coast region were measured in a four pole resistivity cell, using 60 cycle current and a vacuum tube voltmeter of 1 megohm input impedence. The water resistivities ranged from 0.097Ω M at 68°F to 3.52Ω M at 68°F. The chemical analyses of the waters were also available, and the resistivities of these samples were calculated from their analyses according to the methods outlined by Jones and by Tixier, as well as by the method described above, using resistivity vs. concentration data taken from the International Critical Tables.

For the method presented here, the average of the absolute values of the per cent deviation between the measured and calculated resistivities was 3.3 per cent, the calculated resistivity being on the average 1.1 per cent too great. For the Park Jones method, which uses a series of conversion factors to change the primary and secondary salinity and alkalinity to equivalent quantities of *NaCl*, the average of the absolute values of the per cent deviation between the measured and calculated resistivities was 4.6 per cent, with the calculated resistivity being on the average 3.2 per cent too great. For the Tixier method, which adds the reciprocals of the resistivities of the salts formed in the Palmer recombination scheme to obtain the reciprocal of the water resistivity, the average of the absolute value of the per cent deviation was 7.8 per cent with the calculated resistivity being on the average 6.3 per cent too low. Tixier also describes a simplified method of calculation which is identical with that of Park Jones, except that a factor of 0.32 rather than 0.37 is used to convert from secondary salinity to equivalent *NaCl*. Incidentally, in both systems, the 0.4 conversion factor used to go from primary salinity as Na_2SO_4 to equivalent *NaCl* is almost certainly in error. In laboratory prepared solutions of high $SO_4^=$ and low $Cl-$ content, use of this factor led to resistivity errors as large as 60 per cent. As noted before, high $SO_4^=$ concentrations are encountered mainly in the Rocky Mountain regions.

The principal advantage of the method presented here is its speed and convenience. It is felt that for most purposes, and in particular where the $SO_4^=$ concentration is low, any of the three methods of obtaining water resistivity will give reliable results.

REFERENCES

1. Tixier, M. P.: "Water Analysis vs. Water Resistivity," privately circulated, Oct. 22, 1943.
2. Jones, P. J.: *Oil and Gas Journal*, Nov. 18, 1944, 209.
3. Palmer, Chase: *Geol. Survey Bul.*, No. 479, 1911. ★ ★ ★

For Those Who Missed Out

Petroleum Branch Members who failed to attend the AIME Annual Meeting in St. Louis, Mo., Feb. 18-22, may now receive the 10 papers presented there

These Papers Are Now Available in Preprint Form For Only $2.00 Per Set

And In Addition —

Production Review Reports For All Domestic Areas Are Included

At No Extra Cost!

You Get This —

3 Papers on Waterflooding

3 Drilling, Logging and Acidizing Papers

4 Reservoir and Production Engineering Papers

And —

Production Review Reports of All Domestic Areas

ALL FOR ONLY $2.00

Petroleum Branch, AIME
601 Continental Bldg.
Dallas 1, Texas

Please send me_____sets of papers presented at AIME Annual Meeting in St. Louis,. Enclosed is my check (or money order) in the amount of $_____.

Name_____

Address_____

City, State_____

Advertisers Index

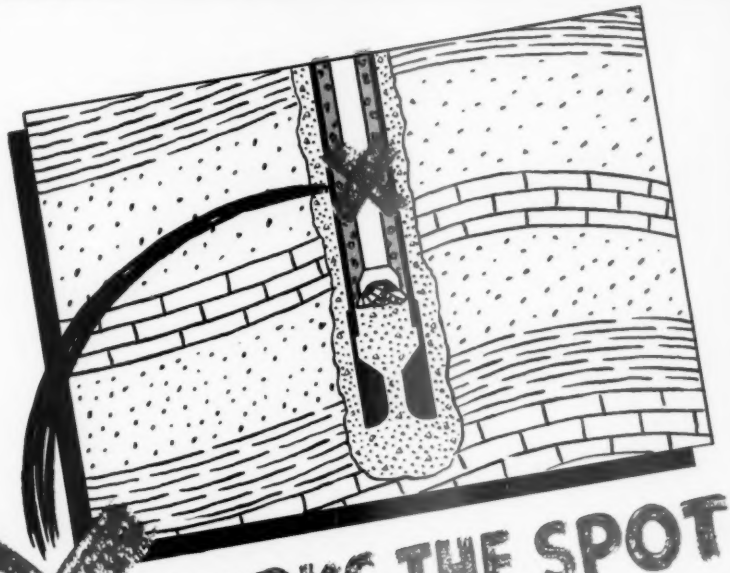
	Page
Allen B. DuMont Laboratories, Inc. *Austin C. Lescarbourg, Croton-on-Hudson, N. Y.*	*
Axelson Manufacturing Co. *Heintz & Co., Los Angeles*	*
Baker Oil Tools, Inc. *Theo. M. Martin Co., San Gabriel, Calif.*	Sec. 1—6,7
Baroid Sales Division, National Lead Co. *Darwin H. Clark Co., Los Angeles, Calif.*	*
B and W Incorporated	Sec. 1—5
Clark Bros. Co., Inc. *Harold Warner Co., Buffalo, N. Y.*	*
Core Laboratories, Inc. *Duvall Williams, Dallas, Tex.*	Sec. 1—4
Dowell Incorporated *MacManus, John & Adams, Inc., Detroit, Mich.*	Sec. 1—8
Eastman Oil Well Survey Co. *Ted Workman Advertising, Dallas, Tex.*	*
G. M. Giannini & Co., Inc. *Western Advertising Agency, Los Angeles, Calif.*	*
Grove Regulator Co. *Rives, Dyke and Co., Houston, Tex.*	*
Halliburton Oil Well Cementing Co. *Lennan & Sanders, Dallas, Tex.*	*
Harry W. Dietert Co.	*
Johnston Oil Field Service Corp. *Wallace Davis & Co., Houston, Tex.*	*
Lane-Wells Co. *Darwin H. Clark Co., Los Angeles, Calif.*	Fourth Cover
Larkin & Co., Inc. *Baycura Advertising, Butler, Penn.*	*
Lufkin Foundry & Machine Co. *Cudlipp Advertising Agency, Lufkin, Tex.*	Sec. 1—24
Magnet Cove Barium Corp. *Rives, Dyke and Co., Houston, Texas*	Third Cover
Oil Base, Inc. *Dozier-Graham-Eastman, Los Angeles, Calif.*	*
Otis Pressure Control, Inc. *Dan Goodrich, Dallas, Tex.*	*
Professional Services	Sec. 1—2
The Second National Bank, Houston, Tex. *Gano, Bachrodt, Edwards, Inc.*	Sec. 2—2
Schlumberger Well Surveying Corp. *Rives, Dyke & Co., Houston, Tex.*	Second Cover
The Geolograph Co., Inc. *Lowe Runkle Co., Oklahoma City, Okla.*	Sec. 2—3
United Geophysical Co., Inc. *Dozier-Graham-Eastman, Los Angeles, Calif.*	*
Welex Jet Services, Inc. *Albert Evans & Assoc., Ft. Worth, Tex.*	Sec. 1—1

* In previous issues

PETROLEUM BRANCH MEETING CALENDAR

MARCH Through AUGUST

MARCH		MAY		JULY	
15	South Plains Sub-Section	3	Illinois Basin Chapter	3	Delta Section
15	Oklahoma City Section	8	Delta Section	5	Illinois Basin Chapter
21	Kansas Section	9	Southwest Texas Section	9	Mid-Continent Section
26	Pacific Petroleum Chapter	14	Mid-Continent Section	18	Kansas Section
		16	Kansas Section	19	South Plains Sub-Section
		17	South Plains Sub-Section	19	Oklahoma City Section
		17	Oklahoma City Section	23	Pacific Petroleum Chapter
		28	Pacific Petroleum Chapter		
APRIL		**JUNE**		**AUGUST**	
5	Illinois Basin Chapter	5	Delta Section	2	Illinois Basin Chapter
9	Mid-Continent Section	6	Southwest Texas Section	7	Delta Section
10	Delta Section	7	Illinois Basin Chapter	13	Mid-Continent Section
11	Southwest Texas Section	11	Mid-Continent Section	15	Kansas Section
18	Kansas Section	20	Kansas Section	16	South Plains Sub-Section
19	South Plains Sub-Section	21	South Plains Sub-Section	16	Oklahoma City Section
19	Oklahoma City Section	21	Oklahoma City Section	27	Pacific Petroleum Chapter
23	Pacific Petroleum Chapter	25	Pacific Petroleum Chapter		



X MARKS THE SPOT

where you need these proved

MAGCOBAR PRODUCTS

CEMENT CONTAMINATION

Several times during the drilling of every well cement contamination of mud becomes a problem. These Magcobar Products have been proved effective for pre-treating the mud prior to drilling the cement and restoring the desirable drilling qualities to cement-cut mud. When you encounter cement contamination, use these Magcobar materials . . . separately or in combinations . . . to save rig time and money and eliminate the costly practice of discarding cement-cut mud. Your Magcobar field engineer will gladly give assistance at the rig and there are nearly 300 strategically located Magcobar dealers with stocks of these products, ready to serve you day and night.

MAGNET COVE BARIUM CORP., MALVERN ARK., HOUSTON, TEX.

ONE OF THE DRESSER INDUSTRIES

Magcobar

Complete

DRILLING MUD SERVICE

DEALER

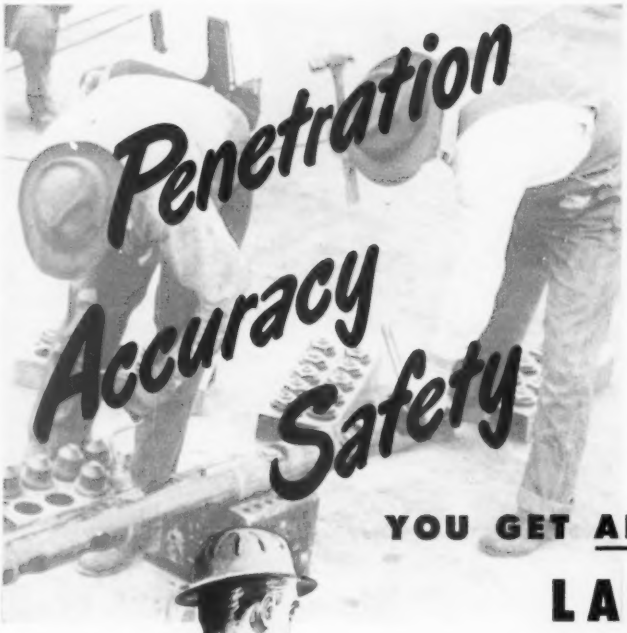
—a protective colloid and powerful dispersing agent—an excellent pre-treatment for conditioning mud prior to drilling cement.

—a complex phosphate for chemically removing cement contaminants.

—an all-purpose mud-treating chemical which supplements phosphates in reconditioning cement-contaminated mud.

—a concentrated colloidal additive for restoring the viscosity and wall-building characteristics.

—a ready-mixed mud in dry form which is resistant to salt and cement contaminants.



YOU GET ALL THREE WITH

LANE-WELLS PERFORATING

"And with Lane-Wells, they all come first—because they're all equally important. Penetration you've got to have—sure—and Lane-Wells delivers it. But you've got to have it in the right place, and you've got to get it there without risking your well or your men. And Lane-Wells does just that. I don't believe you can equal them in measurement accuracy, equipment or oil-country knowledge. They've done a lot of jobs for me, and I *know* they're good!"

Ask Your

LANE WELLS

Man!

LOS ANGELES • HOUSTON • OKLAHOMA CITY

General Offices, Export Office and Plant • 5610 SO. SOTO STREET, LOS ANGELES 58, CALIFORNIA

LANE-WELLS CANADIAN CO. IN CANADA • PETRO-TECH SERVICE CO. IN VENEZUELA

AG-310